DOCUMENT NUMBER: EBL-2011-VRA-003

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FINAL REPORT

JUNE 27, 2011

REVIEW OF DRAFT ELECTRICITY MARKET RULES (DEMR) OF GHANA

PREPARED FOR:

Volta River Authority
28th February Road
Electro-Volta House
Accra, Ghana

PRIVILEGED AND CONFIDENTIAL

PREPARED BY

EBiz Labs Inc
6562 Hallissey Court
Centreville, Virginia 20120-1062
United States of America

Document number: EBL-2011-VRA-003 Date: June 27, 2011

	Name(s)	Date
Drafted:	EBiz Labs Team: Dr. Ron McNamara, Jim Holsclaw, Rick Hoefer, and Raja R. Iyengar	May 4, 2011
Reviewed:	VRA Team: Ebow Acquah, Kwame Amankwah-Twum, Abubakari Obuama Addy, Jacob B. Yawson, Nana Yaw Anane-Binfoh, Mawuli Yawo Kpordze, John M. Mbeele	June 17, 2011
Revised:	EBiz Labs Team: Dr. Ron McNamara, Jim Holsclaw, Rick Hoefer, and Raja R. Iyengar	June 27, 2011
Approved:		
	FINALIZED:	

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Glossary

Term	Acronym	Definition
California Independent System Operator	CAISO	
Cogeneration		Production of electricity from steam, heat, or other forms of energy produced as a by-product of another process.
Curtailment		A reduction in the scheduled capacity or energy delivery of a transaction.
Dispatcher		Performing the activities of a Market Administrator/Operator; responsible for the real time operation of the power system.
Distribution Factor		The portion of a transaction, typically expressed in per unit that flows across a transmission facility (Flowgate).
Draft Ghana Electricity Market Rules	DEMR	This set of market rules.
Electricity Corporation of Ghana	ECG	
Economic Dispatch		The allocation of demand to individual generating units on line to effect the most economical production of electricity.
Electrical Energy		The generation or use of electric power by a device over a period of time, expressed in kilowatt hours (kWh), megawatt hours (MWh), or gigawatt hours (GWh).
Electric Reliability Council of Texas	ERCOT	
Electric Transmission Utility	ETU	

Term	Acronym	Definition
Element		Any electrical device with terminals that may be connected to other electrical devices such as a generator, transformer, circuit breaker, bus section, or transmission line. An element may be comprised of one or more components.
Energy Management System	EMS	
Financial Transmission Right	FTR	The right to receive or pay the difference between two locational marginal prices.
Generation Shift Factor	GSF	A factor to be applied to a generator's expected change in output to determine the amount of flow contribution that change in output will impose on an identified transmission facility.
Generator-to-Load Distribution Factor	GLDF	The algebraic sum of a Generator Shift Factor and a Load Shift Factor to determine the total impact of a transaction on an identified transmission facility.
Grid Code		National Electricity Grid Code
Hourly Value		Data measured on a Clock Hour basis.
Independent System Operator – New England	ISO-NE	
Limiting Element		The element that is 1.)either operating at its appropriate rating, or 2,) would be following the limiting contingency. Thus, the Limiting Element establishes a system limit.
Load Shift Factor	LSF	A factor to be applied to a load's expected change in demand to determine the amount of flow contribution that change in demand will impose on an identified transmission facility.

Term	Acronym	Definition
Load Serving Entity	LSE	Secures energy and transmission service (and related services) to serve the electrical demand and energy requirements of its end-use customers.
Locational Marginal Price	LMP	The marginal cost of serving the next increment of load at a given node
Locational Marginal Pricing Contingency Processor	LMPCP	
Marginal Energy Price	MEP	
Market Administrator	MA	Responsible for the administration of the market rules as described in this DEMR.
Market Clearing Engine	MCE	A tool designed to create a "price" at each injection and take-off node (POD or POR)
Market Oversight Panel	MOP	
Market Participant	MP	Entities entitled to participate in the wholesale electric energy markets as defined in this DEMR.
Midwest Independent System Operator	MISO	
National Electricity Market of Singapore	NEMS	
National Interconnected Transmission System	NITS	
New York Independent System Operator	NYISO	
Nodal Price		Same as Locational Marginal Price

Term	Acronym	Definition
Participation Factors		A set of dispatch rules such that given a specific amount of load to serve, an approximate generation dispatch can be determined. To accomplish this, generators are assigned a percentage that they will contribute to serve load.
Point of Delivery	POD	A location that the Transmission Service Provider specifies on its transmission system where a transaction leaves or a Load-Serving Entity receives its energy.
Point of Receipt	POR	A location that the Transmission Service Provider specifies on its transmission system where a transaction enters or a Generator delivers its output.
PJM Interconnection	PJM	
Public Utilities Regulatory Commission	PURC	
Real Power		The portion of electricity that supplies energy to the load.
Real-time		Present time as opposed to future time.
Regulating Reserve		An amount of reserve responsive to Automatic Generation Control, which is sufficient to provide normal regulating margin.
Reliability Assessment Commitment	RAC	Refer to the Open Access Transmission, Energy and Operating Reserve Markets Tariff for the Midwest Independent Transmission System Operator, Inc.
Response Rate		The Ramp Rate that a generating unit can achieve under normal operating conditions expressed in megawatts per minute (MW/Min).
Schedule		(Verb) To set up a plan or arrangement for a transaction. (Noun) An Interchange Schedule.

Term	Acronym	Definition
Security Constrained Economic Dispatch	SCED	Used to balance real-time energy flows and to accomplish re-dispatch that is necessary because of transmission constraints.
Security Constrained Unit Commitment	SCUC	A unit commitment package used to schedule resources ahead of the Operating Day.
Short Run Marginal Cost	SRMC	The sum of the variable operating and maintenance costs and the fuel costs associated with the operation of the generating facility.
Standing Reserve		Any reserve provided by generation registered facility not classified as "spinning-reserve".
System		A combination of generation, transmission, and distribution components.
System Marginal Price	SMP	See "Uniform Ghana Energy Price"
System Operator		An individual at a control center whose responsibility it is to monitor and control that electric system in real time.
Telemetering		The process by which measurable electrical quantities from substations and generating stations are instantaneously transmitted to the control center, and by which operating commands from the control center are transmitted to the substations and generating stations.
Thermal Rating		The maximum amount of electrical current that a transmission line or electrical facility can conduct over a specified time period before it sustains permanent damage by overheating or before it sags to the point that it violates public safety requirements.

Term	Acronym	Definition
Transmission		An interconnected group of lines and associated equipment for the movement or transfer of electric energy between points of supply and points at which it is transformed for delivery to customers or is delivered to other electric systems.
Transmission Constraint		A limitation on one or more transmission elements that may be reached during normal or contingency system operations.
Transmission Operator		The entity responsible for the reliability of its transmission system, and that operates or directs the operations of the transmission facilities.
Uniform Ghana Energy Price	UGEP	The single price load pays across Ghana.

SECTION A: EXECUTIVE SUMMARY

Major Issues and Findings

The purpose of this report/analysis is to (1) review, (2) comment and, (3) where appropriate or necessary, make recommendations for improving the proposed electricity market design contained in the Draft Ghana Electricity Market Rules (DEMR). The DEMR are among the most recent steps in a process initiated by the Government in 1994/95. According to LI 1934, "the rules shall ensure that the transmission system provides a fair, transparent, non-discriminatory, open access, safe, reliable, secure and cost efficient transmission and delivery of electricity." The scope of this report is limited to the DEMR and not the National Electric Grid Code.

For reasons that are discussed in Appendix A, the primary focus of any electricity market design exercise must be on how *real time* supply and demand will be equilibrated, i.e. how the system will be "dispatched" so that load and generation are matched at every moment in time. While there have been successful markets that have very different designs, it is generally true that design exercises that have focused on legal, regulatory, and commercial issues rather than real time dispatch have been unsuccessful (e.g. the initial California market). In fact, while poorly designed governance structures (i.e. legal and regulatory structures) may contribute to poor market performance, the success or failure of an electricity market rests almost exclusively on the manner in which the rules specify how real time electricity flows will be balanced and priced.

The market design embodied in the DEMR is largely identical to that implemented in the National Electricity Market of Singapore (NEMS). As in Singapore, the Draft Rules envision that the primary dispatch or coordination tool employed by the market operator will be a market-clearing engine (MCE) designed to create a "price" at each injection and off-take node on the system. The algorithms in the MCE are designed to create, in effect, a market at each node in the electrical system while respecting reliability and then solve for an equilibrium price at each node.[1] A nodal-based design, as compared to a zonal design, because it recognizes the unique characteristics of electricity, is fundamentally sound and represents industry best practices.

With respect to pricing methodology, the provisions in the DEMR are unique:

- Generator*s* will receive the nodal price at their specific location;
- Load across the country will pay a single price called the Uniform Ghana Energy Price (UGEP).

[1] Unlike a "true" commodity market where price serves to ration physical supply and demand, a nodal electricity market equates real time physical supply and demand and then solves for a price that is consistent with that solution.

- The UGEP will be the sum of:

  (1) a capacity charge,
  (2) an ancillary service charge, and
  (3) an energy charge

- The first two components are formulaic and not market-determined.[2]
- The energy charge is "the *short-run marginal cost* of the last generating facility dispatched during the hour."[3] But, as is shown in Appendix A, whenever the system is constrained, the actual marginal cost, and hence the price of serving load on the constrained side of the system will not equal the marginal cost of any generating plant on the system. The pricing methodology in the DEMR, therefore, completely ignores the monetary effects arising from constraints in the transmission system.

Whenever transmission constraints are present as they are in the Ghanaian electricity network, the concept of a single system marginal cost is false. Since transmission constraints including thermal line limits will cause nodal prices to deviate across the system, using a single price is justified **only** in the case where there are no transmission constraints – as is true in Singapore where the government has been committed to spending what is necessary to keep the transmission system constraint free. Thus while the proposed rules themselves are nearly identical to those of the NEMS, the physical transmission network in Ghana is not. Moreover, a constraint-free electricity grid, as is present in Singapore, does not represent an optimal situation. Investment in transmission infrastructure should only take place up to the point where the marginal benefit (i.e. the reduction in the costs caused by constraints) of additional transmission capacity equals the marginal cost of the investment. This criteria implies that the complete elimination of constraints is rarely, if ever, economically optimal.

It is likely that the recommended pricing methodology will, depending, of course, on how it is actually implemented, also result in the creation of larger than necessary financial surpluses being paid to the Market Administrator.[4] The traditional method for giving this surplus back to consumers is through Financial Transmission Rights

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[2] The DEMR provides information on the derivation of the capacity charge but states that GRIDCo is to provide similar information on the ancillary service charge. Thus it is impossible to evaluate this item.

[3] DEMR Rule 4.1.30

[4] To illustrate why; assume a system with only two generators, with marginal costs of $10 and $100 respectively. Assume the $10 generator produces 9MW and the $100 generator produces 1MW. Under the DEMR pricing rules, the $100 generator would set the price. Load would pay $1000, (10MW*$100), but the generators would only receive $190, i.e. (9MW*$10)+(1MW*$100). The ETU as the Market Administrator/Operator would have a surplus of $810 that would have to be returned to load. Changing the pricing to allow for more than a single price to load would significantly reduce the amount of this surplus.

(FTR). However, the proposed market design does not include FTRs,[5] rather the surplus – which by definition is assumed to be small because the design is based on the erroneous assumption of a constraint-free grid – is returned through a credit in the settlement process.[6] The credit is not based on location but instead on the quantity of electricity consumed which further mutes the important locational price signal.

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Conclusions and Recommendations

Regarding electricity transmission, the Government of Ghana has stated that its objective is "that the transmission system provides a fair, transparent, non-discriminatory, open access, safe, reliable, secure and cost efficient transmission and delivery of electricity."[7] In their current form the structure defined by the DEMR will not accomplish these objectives.

From the perspective of market design[8] the DEMR in their current form contain five and potentially six fundamental and fatal flaws that must be addressed and changed if the eventual market is to be successful:

1. Having a single national zonal price for load, given a constrained transmission system, means that some load will pay far less than their true marginal cost while others will pay far more. This pricing is neither fair nor non-discriminatory and will reduce or eliminate the transparency of the dispatch process. It may also risk the reliability of the system because the pricing signals are in direct opposition to the needs of dispatcher in ensuring system reliability, i.e. at locations where the dispatcher would like *greater* load, the price is artificially increased by the pricing rule, thereby *reducing* the quantity of electricity demanded, while at the same time, at locations where the dispatcher would like *less* load the pricing rule *encourages* consumption by artificially reducing the price.

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[5] Interestingly, even the NEMS, where congestion is essentially zero, included FTRs soon after they began operation primarily as a way to return the financial surpluses generated by using marginal losses in the dispatch process.

[6] The financial surplus is the aggregate monetary surplus that arises from the difference between the total amount that consumers paid for the electricity and what all generators received for producing it. GRIDCo, as the market administrator, will bill consumers for the power used and pay the generators for the power produced. If there were no losses or constraints then the amount that GRIDCo collects would be equal to what they would pay out and there would be no financial surplus. As such, the surplus *does not* refer to the difference between the market price and the cost of any specific generator to produce the electricity. See Appendix A for a detailed explanation of how this surplus is created.

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[7] LI 1934 and largely reiterated in LI 1937

[8] Like any market, an electricity market can fail for several reasons including, poor design, flawed implementation, inefficient or incorrect operation, and monopolistic or collusive behavior by either buyers or sellers. As such, good market design, while a necessary requirement is not sufficient for a successful market.

2. Basing price solely on the marginal cost of the "last generating facility dispatched during the hour" reflects an incorrect understanding of the operation of the electricity grid. Every time even a single constraint arises on the grid, the system will have more than one marginal or "last generating" facility. The rules do not specify which one of the two or more marginal plants will set the price. If we assume that it is the most expensive marginal generator, then the pricing mechanism will discriminate against consumers in the unconstrained region. If we assume that it is the less expensive plant then the market will not collect enough revenue to pay the generators. Most importantly, the use of a single marginal price, completely ignores the monetary effects caused by transmission constraints and will lead to inefficient consumption and investment.
3. Given that the market design is based on paying the generators their short run marginal cost, it does not appear the rules allow for the recovery of start up, shut down and minimum run costs. Since the recovery of these costs varies with both level of output and the duration of production they cannot be assumed to be part of the fixed capacity charge. Similarly, the "fixed operation and maintenance" cost component included in Rule 4.1.19 does not explicitly recognize the inclusion of these costs. If generators are unsure whether they will be able to recover their start up, shut down and minimum run costs, secure operation of the transmission system cannot be guaranteed.
4. The DEMR envisions a 1-hour real time market. That is, within the hour there is no market and all necessary actions of the dispatcher are accomplished by command-and-control through the use of ancillary services. However, the DEMR does not contain any information about how the Dispatcher (one of the activities performed by the Market Administrator/Operator) will operate within the hour, i.e. how will congestion that arises within the hour be managed, or how will the loss of a unit or transmission element be managed, etc. Not only is this not transparent it is unlikely to be cost effective.
5. Given the mandated composition of the Market Oversight Panel (MOP) it is clearly intended to be a stakeholder panel; however, the direction of LI 1937 16. (2), which requires that the MOP carry out its operations independently of the ETU would suggest that the inclusion of the CEO and Head of Systems Operations and Control of the ETU poses an inherent conflict between the required independent operation of the MOP and the inclusion of ETU executives on the MOP.
6. In their present form the DEMR are inconclusive as to whether a generator will be paid for providing reserves if they are *dispatchable* but not *dispatched*. If generation facilities are only eligible under the rules to receive payment for providing reserve capacity when they are dispatched this would represent a fatal flaw and would risk the reliability of the system.

There is also one significant but non-fatal flaw: the DEMR do not specify how transmission losses will be priced, i.e. will transmission losses be priced based on average or marginal losses. While either can be used, economic efficiency is obtained by using marginal losses, especially on a transmission system where line losses are significant.

While not directly related to the DEMR, and hence beyond the explicit purview of this report, we note that GRIDCo currently functions as the transmission owner and the Market Operator/Administrator.[9] Should GRIDCo continue to be both the asset owner and Market Operator this would create a potentially significant conflict of interest once the market is operational. As the transmission owner, GRIDCo benefits from additional transmission investment. At the same time, as the entity responsible for dispatching the system, i.e. the Market Operator, GRIDCo has the ability to operate the system such that it appears that additional transmission investment is needed. This is the primary reason why ownership of the transmission system and grid operation have been separated in other electricity markets, e.g. Ontario, Alberta, New England, New York, PJM, MISO, SPP, ERCOT, Singapore, the Philippines, and Australia.[10]

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[9] See http://www.gridcogh.com/site/aboutus.php, for this description of GRIDCo's activities:

Overview

BACKGROUND

GRIDCo was established in accordance with the Energy Commission Act, 1997 (Act 541) and the Volta River Development (Amendment) Act, 2005 Act 692, which provides for the establishment and exclusive operation of the National Interconnected Transmission System by an independent Utility and the separation of the transmission functions of the Volta River Authority (VRA) from its other activities within the framework of the Power Sector Reforms.

GRIDCo was incorporated on December 15, 2006 as a private limited liability company under the Companies Code, 1963, Act 179 and granted a certificate to commence business on December 18, 2006. The company became operational on August 1, 2008 following the transfer of the core staff and power transmission assets from VRA to GRIDCo.

FUNCTIONS

GRIDCo's main functions are to:

1. Undertake economic dispatch and transmission of electricity from wholesale suppliers (generating companies) to bulk customers, which include the Electricity Company of Ghana (ECG), Northern Electricity Department (NED) and the Mines;
2. Provide fair and non-discriminatory transmission services to all power market participants;
3. Acquire, own and manage assets, facilities and systems required to transmit electrical energy;
4. Provide metering and billing services to bulk customers;
5. Carry out transmission system planning and implement necessary investments to provide the capacity to reliably transmit electric energy; and manage the Wholesale Power Market.

The establishment of GRIDCo is intended to develop and promote competition in Ghana's wholesale power market by providing transparent, non-discriminatory and open access to the transmission grid for all the participants in the power market particularly, power generators and bulk consumers and thus bring about efficiency in power delivery.

[10] We note that Sections 5, 6, and 7 of LI 1934 and Section 11 of LI.1937 appear to be inconsistent with having the Market Operator own the transmission assets.

Given that the flaws in the DEMR are *foundational* it is premature in most cases to make narrow or precise recommendations. Instead the following six overarching recommendations address the fundamental flaws in the current version of the DEMR:

1. *Section 4: Market Operation* and the relevant Appendices comprising the foundation of the market must be rewritten. Other sections or components of the rules, while important, e.g. governance, are secondary in importance to the rules of how real time power flows will be balanced and priced. Given the fundamental flaws in the current version of Section 4, it needs to be re-drafted with particular attention on:
   1.1. Pricing for load,
   1.2. Whether the market should be a self-commitment or central commitment market,
   1.3. Recovery of start up, shut down and minimum run costs,
   1.4. Defining the procedures/actions taken by the Market Administrator within the hour of real time operations,
   1.5. Payment for providing reserve, and
   1.6. How transmission losses will be priced.
2. The re-drafting of Section 4 should be done in a collaborative stakeholder process to ensure that all possibilities are considered and discussed.
3. Once Section 4 has been re-drafted and has the approval of the industry, work should be undertaken to re-draft or edit the remaining sections of the DEMR to ensure they are consistent with the new language and paradigm.
4. A process should be instituted to ensure that the eventual market rules and the National Electric Grid Code are consistent and aligned.
5. Once the market is operational, if GRIDCo serves as the Market Administrator/Operator and continues to own transmission assets then additional rules will need to be written in order to eliminate the inherent conflict of interest.[11]
6. There should be a structural, rather than on a case-by-case basis, solution to the potential conflicts of interest that exist between the membership of the Market Oversight Panel and the issues they will be required to make decisions on.[12]

Commented [A3]: Which is the best option: separation of functions or removal of inherent conflict of interest.

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[11] As a natural monopoly the value of the transmission asset company is approximated by the amount of capital employed and there is an inherent incentive for the company to desire more capital. In contrast the objective of the transmission system operator is to facilitate least cost dispatch, i.e. a dispatch that minimizes the cost of using the existing infrastructure, including generation, transmission and, if available, demand response. Removing the inherent conflict of interest would, in essence mean changing the basis upon which the transmission asset company is compensated, i.e. the revenue of the transmission asset owner would no longer be specifically tied to the amount of capital employed.

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[12] While the DEMR can be interpreted as expanding the functions of the MOP provided under L.I. 1937, Section 16 (2) (a), (c) and (f) of LI 1937 requires the MOP "to monitor the general performance of the transmission system functions of the utility," "to review the operations of the transmission system," and "to ensure the effective and consistent application of the rules and standards in the Grid Code.," all of which potentially involve the activities performed by the Market Administrator.

SECTION B: MAIN REPORT

Introduction

Beginning in 1994/95, the Government of Ghana has pursued a broad policy with respect to electricity designed to attract private investment into the sector.[13] In this regard, Ghana is similar to many other countries that began reforming their energy sectors at this time.[14] In almost all cases where sector reform has been initiated, the motivations are some *combination* of (1) the need to reduce government fiscal involvement in the sector, (2) price distortions, and (3) technological progress that made small scale generation economically competitive with large-scale generation.

Since electricity obeys the laws of physics, reform by definition cannot change the characteristics of the commodity; rather, it involves changing the status quo roles and relationships among the government, electricity regulator, market participants and stakeholders in respect to industry business practices, which collectively comprise the institutional structure. Thus, beginning in 1997 when the Public Utilities Regulatory Commission (PURC) and the Energy Commission (EC) were established by the PURC Act, 1997 (Act 538) and EC Act, 1997 (Act 541) respectively, and the subsequent amendment of the VRA Act in 2005 to remove the transmission functions from the mandate of VRA (Act 692 of 2005), the Ghana Grid Company Limited ("GRIDCo") was incorporated on 15th December 2006 as an autonomous limited liability company under the Companies Code of Ghana, 1963 (Act 179) to assume the transmission function. GRIDCo has been set up as a separate and independent entity and under the Electricity Transmission (Technical, Operational and Standards of Performance) Rules, 2008 (LI 1934) and Electricity Regulations, 2008 (LI 1937) with the transitional provision, it is to own and operate the National Interconnected Transmission System (NITS) to provide "open access" transmission services to all wholesale electricity market suppliers/participants and administer Ghana's emerging electricity market.[15] With the Parliament of Ghana enacting LI 1934 and LI 1937, the Government of Ghana has effectively reduced its role in the power sector and has thereby changed, or is in the process of changing, the relationships and established business practices.

In effect the Government has, over the past 10-15 years, been changing the institutional structure and commercial relationships of the electricity industry from one that was based on centralized command and control regulated by the Minister responsible for Energy, to one that is increasingly based on competitive market

[13] The Power Sector Reform Program (PSRP) was initiated in 1995.
[14] The UK, Australia, New Zealand, Nordpool (initially Norway and Sweden and then Finland, Western Denmark and finally Eastern Denmark), and sections of the United States are all examples of countries/regions that began reform programs during the 90's.
[15] Ownership and operation of the market creates a potential conflict of interest for GRIDCo. Inefficient but nonetheless reliable, dispatch, i.e. operation of the grid, may well lead to unneeded transmission investment which would benefit ETU as the owner of the transmission system.

forces. Prior to the reform process, generation and transmission were vertically integrated within VRA while the distribution and retail businesses were similarly integrated within the Electricity Corporation of Ghana (ECG, renamed the Electricity Company of Ghana) and the Northern Electricity Department (a Department of VRA in charge of distribution of electricity in the Northern part of Ghana).[16] ECG has been converted from statutory corporation status to a company registered under the Companies Code, 1963.

The Government's desire to introduce competition in the electricity sector, necessarily means that activities that can be provided in a competitive environment e.g. generation, retailing) must be separated from activities that are best provided by a monopoly (e.g. transmission, distribution). Thus, what was once a vertically

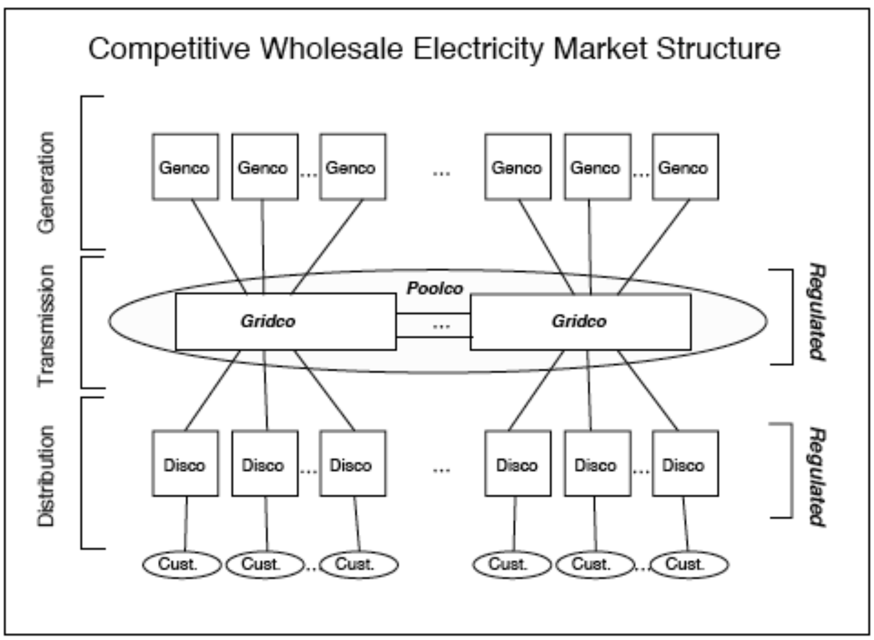

Figure 1: Diagrammatic Representation of a Competitive Electricity Industry

integrated sector, with generation, transmission, retailing and distribution all performed by a single integrated entity,[17] will increasingly become dis-aggregated

[16] Retail and distribution activities remain integrated within ECG and NED.
[17] At least on a regional basis.

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structure. Figure 1, provides a generic diagrammatic representation of what the power sector in Ghana will eventually look like[18] The diagram, by disaggregating electricity production and consumption into the three primary activities – generation, transmission and distribution/retailing – highlights the importance of the activities of the transmission sector which is comprised of the "Gridco"[19], i.e. the physical transmission network, and the "Poolco", i.e. the agent responsible for coordinating generation in order to meet load by granting access to the transmission network. There are no inherent ownership assumptions in the diagram, i.e. the "Genco's", or generation companies, could be either State-owned or Independent Power Producers as could be the "Disco's", or Distribution Companies. Moreover, the Disco's may or may not be vertically integrated with a retail business. Neither should it be inferred from the diagram that the activities of the Poolco and the Gridco must be performed by the same entity.

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Deleted: Figure 1 provides a generic diagrammatic representation of what the government is ultimately attempting to accomplish.[18]

The DEMR produced by the Energy Commission and the focus of this report are the rules that outline how the "Poolco" will operate. In this context, "operate", means how the "Poolco" will allocate physical transmission capacity in real time so as to match supply and demand. A necessary (but not sufficient) requirement to foster competition is to ensure this allocation process is fair and non-discriminatory, i.e. that one or more of the "Genco's" in Figure 1 are not given preferential access rights to the transmission network. Therefore, with respect to electricity, creating the platform from which a "market" can develop necessarily means ensuring fair and non-discriminatory access to the transmission grid. That is, all parties need to be able to obtain transmission capacity on a fair and non-discriminatory basis.

However, the physical characteristics of electricity necessarily mean that the transmission system cannot be perfectly "rationed" prior to real time in as much as the capacity of the transmission system at any point in time cannot be known with certainty until power is actually flowing. Moreover, the capacity of the transmission network is not simply a function of the physical infrastructure of generation, and transmission facilities and load, but also a result of the decisions made by the Dispatcher in matching supply and demand. As highlighted by Paul Joskow and Richard Schmalensee back in 1983:

> *The role of the transmission network in transporting power and in coordinating the efficient supply of electricity in both the short run and the long run is the heart of a modern electric power system. The transmission system is not just a transportation network that moves electricity from individual generating plants to load centers.*

[18]While the separation of functions shown in this diagram has numerous authors, this particular example is drawn from a presentation by William W. Hogan, "Poolco: What's the trick? Coordination for Competition, Transmission Pricing and Open Access in the Restructured Electricity Market." July 18, 1995, p. 7. (seehttp://www.hks.harvard.edu/fs/whogan/)

[19]We will distinguish between the generic "Gridco" and the specifically designated entity in Ghana entitled "GRIDCo".

> *Transmission plays the most fundamental role in achieving the economies of electric power supply that modern technology makes possible. The practice of ignoring the critical functions played by the transmission system in many discussion of deregulation almost certainly leads to incorrect conclusions about the optimal structure of an electric power system.*[20]

In this passage, Joskow and Schmalensee, writing without the benefit of current vernacular on the topic point directly to the importance of the dispatch or coordination function ("…not just a transportation network..."). Creating a market is an exercise in designing rules that provide fair and non-discriminatory access to the dispatch function. Unless the electrical grid is so "overbuilt" relative to the requirements, including reliability, that transmission capacity need never be rationed; the starting point of good market design is with the dispatch function itself because this is the foundation of all wholesale electricity markets.

At this point it is relevant to emphasize the subtle, and often overlooked, distinction between an electricity "market" and the physical coordination of electricity. For most commodities and services, the market mechanism works to coordinate the activities of participants by creating a price that induces behavior on the part of its participants that leads to a balance between supply and demand. For example, when the quantity supplied exceeds the quantity demanded at a given price, the price will fall which induces suppliers to produce less and for consumers to purchase more and the "problem" of excess supply is eliminated. This standard textbook explanation glosses over the fact that, in the real world it takes time for the price mechanism to "work", i.e. it takes time for prices to change and for participants to react to new prices. Unfortunately, when it comes to electricity we do not have that luxury – time is critical! The electrical system operates at a far faster pace than can the market. Supply and demand on an electrical system must be balanced within a narrow band at every instant in time and the price mechanism cannot coordinate buyers and sellers that quickly. As a result it is misleading and incorrect to talk about a real time[21] electricity market. In reality, a real time market is actually a very short-term forward market equal to the dispatch interval (normally either 5 or 15 minutes). Since the price mechanism requires too much time to work, every electricity system requires explicit or direct coordination. Indeed, while much time in the electricity market design process can be devoted to discussions of governance, committee membership, arbitration, market monitoring, etc., what matters first and foremost with respect to the eventual operation of the market are the rules pertaining to how supply and demand will be coordinated in real time, i.e. the dispatch rules.

[20]Joskow, Paul L. and Richard Schmalensee, Markets for Power: An Analysis of Electrical Utility Deregulation, MIT Press, 1983. P. 63.

[21]The time when actual physical generation and physical consumption are taking place.

Issues and Findings

Introductory Comments

With respect to the basic tenets of good electricity market design the industry has, over the past 10-15 years, converged around a few central tenets that must be in place if the market is going to work. This convergence has come across both geographic boundaries as well as initial conditions. That is, it does not matter whether a system is based in Asia, North America or Europe or if it has a preponderance of hydro or thermal based generation – the basic tenets of good electricity market design are the same.

Successful electricity market designs:

1. Are based on the physical reality of electricity, i.e. nodal and not zonal congestion management,
2. Provide the correct economic incentives, i.e. prices, to the participants so that their actions are consistent with least cost reliable dispatch,
3. Clearly define how and when non-market, i.e. command-and-control, interventions by the dispatcher will take place,
4. Either directly provide or indirectly allow for the development of efficient financial risk management instruments for price volatility arising from constraints and
5. Protect the market from the exercise of market power.

Every electricity market must address by whom and how each of these five tasks will be performed. Refer to the detailed issues addressed in Appendix B.

Legal and Regulatory Framework

The legal and regulatory review of this report incorporates an evaluation of Electricity Regulation, 2008 (LI 1937) (hereinafter referred to as "LI 1937" or "Electricity Regulation"), the Energy Commission Act, 1997 (Act 541) (hereinafter referred to as the "Energy Commission Act"), the National Electricity Grid Code, the Energy Commission Licensing Manual for Service Providers in the Electric Supply Industry and the Market Rules. LI 1937, which was issued under Sections 56 (1) (a) (i) to (vi) and (c) of the Energy Commission Act mandates the development of a wholesale electricity market and associated Market Rules, the implementation of which shall be based on the fundamental framework of ensuring the procurement and dispatch of electricity from a wholesale supplier to a bulk customer and distribution company in a fair, transparent and non-discriminatory manner.[22] This framework of fair, transparent and non-discriminatory access to the transmission system and associated dispatch has formed the basis of wholesale electricity

[22] See LI 1937 4. (2).

markets throughout the United States vs. the implementation of *Order Nos. 888*[23]and *2000*[24]of the Federal Energy Regulatory Commission.

LI 1937's required development of a wholesale electricity market provides certain requirements related to market structure and operation. For the purposes of this review it is assumed that VRA will participate in the wholesale electricity market as a Market Participant. It is important to note, however, that LI 1937 and the DEMR impose a barrier to entry into the wholesale electricity market by requiring that entities seeking market participant status meet specific licensure requirements defined in LI 1937 and the Market Rules.[25]

As discussed in detail below, LI 1937 does not specifically identify entities that have been exempted from licensing requirements under the Energy Commission Act, such as VRA's exemption for hydro generation on the Volta River Basin, in its listing market participants to whom the regulations apply. Also discussed in detail below, the DEMR are internally inconsistent in the identification of classes of persons who may apply for market participant status.

The registration and market participant structure forwarded by LI 1937 and the DEMR is presumptive rather than proscriptive in that they seek only to establish a threshold for participation, but do not impose an obligation of participation in the wholesale electricity market. Neither LI 1937 nor the DEMR specifically require classes of generation or load to participate in the wholesale electricity market and as such the market appears to be voluntary by nature.

Regulation 5 of LI 1937 dictates that the market structure consist of a spot market and bilateral contracts with copies of the bilateral contracts being lodged with the Electric Transmission Utility ("ETU"), the Commission and the Public Utilities Regulatory Commission.[26] The market structure dictated by LI 1937 specifically excludes the Akosombo and Kpong hydro-electric dams from being the subject of bilateral contract.[27] These Regulations are echoed in DEMR Rule 4.1.04. The exclusion of these hydro-electric dams from bilateral contracting effectively forces

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[23] Promoting Wholesale Competition Through Open Access Non-discriminatory Transmission Services by Public Utilities; Recovery of Stranded Costs by Public Utilities and Transmitting Utilities, Order No. 888, 61 FR 21540 (May 10, 1996), FERC Stats. & Regs. ¶ 31,036 (1996), order on reh'g, Order No. 888-A, 62 FR 12274 (Mar. 14, 1997), FERC Stats. & Regs. ¶ 31,048 (1997), order on reh'g, Order No. 888-B, 81 FERC ¶ 61,248 (1997), order on reh'g, Order No. 888-C, 82 FERC ¶ 61,046 (1998), aff'd in relevant part sub nom. Transmission Access Policy Study Group v. FERC, 225 F.3d 667 (D.C. Cir. 2000) (TAPS v. FERC), aff'd sub nom. New York v. FERC, 535 U.S. 1 (2002).

[24] Regional Transmission Organizations, Order No. 2000, 65 FR 809 (Jan. 6, 2000), FERC Stats. & Regs. ¶ 31,089 at 31,142 (1999), order on reh'g, Order No. 2000-A, 65 FR 12088 (Mar. 8, 2000), FERC Stats. & Regs. ¶ 31,092 (2000), aff'd sub nom. Public Utility District No. 1 of Snohomish County, Washington v. FERC, 272 F.3d 607 (D.C. Cir. 2001).

[25] *See* LI 1937 8 and Market Rule 1.6.01.

[26] *See* LI 1937 5. (1), (3).

[27] *See* LI 1937 5. (2).

these resources into the spot market to be a taker of the market price. Regardless of the cost structure of the excluded resources as compared to thermal generation or the anticipated system marginal price in Ghana, the prohibition on bilateral contracting forces exposure to the market price with no apparent hedge. While there may be certain operational circumstances of the transmission grid that justify the prohibition on bilateral contracting at VRA's hydro-electric dams, these circumstances are not specifically identified in the legislation or DEMR. Furthermore, LI 1937 and the DEMR appear to be silent as to the treatment of any bilateral contracts or agreements that pre-date the Electricity Regulation or the Market Rules. Treatment of such contracts was a significant barrier to the commencement of certain markets in the United States.

Regulations 16 and 17 of LI 1937 establish the Electricity Market Oversight Panel ("MOP"). Pursuant to LI 1937 Regulation 16, the MOP is responsible for the supervision of the administration and operation of the wholesale electricity market. This supervision is to be carried out independently of the ETU.[28] Regulation 17 of LI 1937 which establishes the composition of the MOP, specifically identifying the titles of the panelists as set forth below:

17.1 The Electricity Market Oversight Panel consists of:

a) a Chairperson,
b) the Executive Secretary of the Commission,
c) the Executive Secretary of the Public Utilities Regulatory Commission,
d) the Chief Executive Officer of the Utility,
e) the Head of Systems Operations and Control of the Utility,
f) one Representative nominated by each of the following
a. the Distribution Licensees, and
b. the Bulk Customers,
g) two Representatives nominated by the Wholesale Suppliers,
h) one Person responsible for the administration of the Electricity Market Oversight Panel, and
i) one other Person with knowledge and experience in matters relevant to the wholesale electricity market.

17.2 The members of the Electricity Market Oversight Panel shall be appointed by the Minister.

Given the mandated composition above, the MOP is clearly intended to be a stakeholder panel; however, the direction of LI 1937 16. (2), which requires that the MOP carry out its operations independently of the ETU would suggest that the inclusion of the CEO and Head of Systems Operations and Control of the ETU poses an inherent conflict between the required independent operation of the MOP and

[28] *See LI* 1937 16. (1), (2)

the inclusion of ETU executives on the MOP. While LI 1937 22 (1) requires the disclosure of interest and disqualification of a member of the MOP when reviewing an issue the specific member has an interest in, the general purpose of the MOP (i.e., reviewing the operation and administration of the market managed by the ETU) would suggest that any ETU staff member would have to disclose an interest in potentially any activity of the MOP.

Market Participation

Pursuant to DEMR Rule 2.1.02, participation in the Electricity Market is predicated upon the establishment of Market Participant status and registration of the facilities to or from which physical service is to be conveyed under the Market Rules. Facilities registration requirements are provided in DEMR Rules 2.5.02 through 2.5.06 and are applicable upon the determination of either Market Participant or Conditional Registration status. While the application for Market Participant status and registration of facilities is sequential under the DEMR, these processes could be combined into one registration process for ease of implementation as has been done in US markets like the Midwest ISO's Energy and Operating Reserves Market where the application for market participant status includes the required asset registration.

The ETU's review of Market Participant applications and granting of Market Participant status is focused on the applicants' satisfaction of general technical, prudential and applicable licensing requirements. As such, the Market Participant registration process establishes a threshold participation requirement, with more granular technical requirements being defined in the facilities registration requirements.

Of importance is the requirement that the Market Participant applicant execute the ETU/MP *agreement* in 2.1.03 (c). This requirement assumes there is (or will be) an agreement executed by the ETU and Market Participant; however, the referenced ETU/MP *agreement* is not included in the Market Rules. Furthermore, the italicized term "*ETU/MP agreement*" is not contained in Section 6, Definitions and Acronyms of the DEMR. The terms "*ETU/MA agreement*" and "*MA/Market Participant agreement*" are defined in Section 6 as the following:

> *1.1.88* *ETU/MA agreement* means the agreement required to be executed between the *ETU* and the *MA* as required by the conditions of the *ETU*'s *electricity license* and pursuant to which the *ETU* and the *MA* agree, among other matters, to be bound by the *market rules*.
>
> *1.1.128* *MA/Market Participant (MP) agreement* means the agreement required to be executed between the *MA* and each *market participant* referred to in Section 1.2.2.3 of Chapter 2 and pursuant to which the *MA* and the *market participant* agree, among other matters, to be bound by the *market rules*;

The required execution of an *ETU/MP agreement* appears to correspond with Regulation 8. (1) (c) of LI 1937, which states in part that a person shall not participate in trading in the wholesale electricity market unless that person has entered into a contractual arrangement with the Utility. Ultimately, the agreement entered into by and between the ETU and the Market Participant will need to be defined and incorporate, most likely by reference, the appropriate provisions of LI 1937, the Grid Code and the Market Rule as referenced in Regulation 8. (2) of LI 1937.

The rules related to the application for registration as a Market Participant are set out in DEMR Rules 2.3.01 through 2.3.14. Pursuant to DEMR Rules 2.3.01 (b), the participation registration application shall be in the form set out in the applicable Market Manual, which has not been provided as part of the review.

In general, the timeline for ETU review of Market Participant applications provided in DEMR is relatively brief, with requests for additional information from the applicant being made within 10 business day pursuant to and a final determination of market participant status within 20 business days, unless otherwise determined by the ETU due to a need for additional information. One notable feature of the application process is the provision of *conditional registration* status, which allows an entity to proceed with the registration process prior to completion of the Market Participant application process when the ETU has requested additional information from the applicant.

Pursuant to DEMR Rules 1.6.01 and 2.2.01 certain classes of persons may apply for registration as *market participants*. The identification of classes focuses on wholesale electricity suppliers licensed by the Energy Commission or exempted from holding a license by the Energy Commission Act, electricity distribution utilities licensed under the Energy Commission Act and bulk customers of electricity defined under the Energy Commission Act. Both 1.6.01 and 2.2.01 have the heading of "Classes of Market Participants"; however, the Rules are inconsistent in that DEMR Rule 1.6.01 includes an additional class of persons in (e) identifying any Government department that generates electricity before the market rules came into force as a person that may apply for registration as a market participant. Rule 2.2.01 has omitted this provision.

In addition, Rule 2.2.01 includes a statement under subpart (a) specifically identifying "wholesale electricity suppliers exempted from holding a licence under the Energy Commission Act" as a person who may apply for registration as a Market Participant. This provision is omitted from Rule 1.6.01.

DEMR Rules 1.6.01 and 2.2.01 appear to correspond to Regulation 2 of LI1937 detailing the application of the Electricity Regulations. Regulation 2 of LI 1937 does not include certain classes of market participants contemplated by the Market Rule. More specifically, the Application section of LI 1937 does not specifically reference such persons: (a) that have been exempted from the requirement to hold a licence under the Energy Commission Act; (b) that have been granted an electricity license permitting them to trade in the wholesale electricity market; or, (c) a Government department that generates electricity before the market rules come into force.

In addition to the inconsistency between the DEMR and LI 1937 discussed above, there is also a notable omission of any reference to an entity that is exempted from the requirement to hold a licence under the Energy Commission Act. DEMR Rule 2.1.03 provides a specific accommodation for entities applying for market participant status that have been exempted from the requirement to hold an electricity license. Pursuant to Section 30 of the Energy Commission Act, VRA has been exempted from the requirement for a license to produce and supply wholesale electricity from the hydropower installations on the Volta River Basin:

Section 30 Exemption

The Volta River Authority established under the Volta River Act, 1961 (Act 46) is exempted from the requirement for license to produce and supply wholesale electricity from the hydropower installations on the Volta River Basin.

In addition to Regulation 2, Regulation 8 also omits a reference to entities exempted from holding a license under the Energy Commission Act:

Registration

8. (1) A person shall not participate in trading in the wholesale electricity market unless that person has

(a) an operating license or permit issued by the Commission,
(b) registered with the Utility,
(c) and entered into a contractual arrangement with the Utility

(2) The contractual arrangement with the Utility, the market rules, the National Electricity Grid Code and these Regulations shall define the rights and obligations of a market participant in the wholesale electricity market.

(3) The Utility shall maintain a register of market participants.

Sub section (d) of both DEMR Rule 1.6.01 and 2.2.01 reference a licence to "trade" in the wholesale electricity market. The term "trade" is not an italicized item in the DEMR to reference the defined term *trade* in Section 1.1.249 of the DEMR Rule1.1.249, which *trade* means (a) to sell *electricity*, *ancillary services* or any other *electricity* related product or service to a person other than a *consumer* who is being *supplied* and sold *electricity* by a *retail electricity licensee*; or (b) to purchase *electricity*, *ancillary services* or any other *electricity* related product or service, where such purchase is made by a person other than a *consumer* who is being *supplied* and sold *electricity* by a *retail electricity licensee*;

Because the statements in Rules 1.6.01 and 2.2.01 (d), respectively, are separate and apart from the requirement that market participant applicants have licences for wholesale electricity supply and distribution in subsections (a) and (b) of Rules 1.6.01 and 2.2.01, respectively, a question exists as to whether the licence to "trade" referred to in 1.6.01 and 2.2.01 (d) is the distribution and sale licence as identified in Appendix D of the Energy Commission Licensing Manual.

Pursuant to DEMR Rule1.6.02, any person that is not the ETU, MOP or a market participant shall not be entitled to any rights or benefits under the Market Rules, any Market Manual or the System Operation Manual. This provision effectively limits third party participation in the market.

Pursuant to DEMR Rules 1.6.04 through 1.6.08, Market Participants may use agents in performing their functions under the Market Rules and Manuals. Pursuant to Rule 1.6.04, the Market Participant is bound by the acts of its agent and remains solely liable for the due performance of its obligations.

DEMR Rules 1.6.06 through 1.6.07 address the ETU's authority to notify a Market Participant that the use of an agent is not in the best interest of the market. Of note is the ten (10) business day notice period and effective date for the cessation of the agent. This notice period and required setting of an effective date appear to be in the interest of the Market Participant and should allow sufficient time for the Market Participant to make arrangements to carry out its obligations under the Market Rules in the absence of the disqualified agent.

Section 3.6 of the Market Rules establishes the enforcement and penalty regime under the Market Rules. Pursuant to Rule 3.6.01 and 3.6.02, enforcement responsibilities are to be carried out by the MOP and administered by the ETU.

The imposition of the obligation to enforce compliance with the Market Rules appears to have been omitted from the MOP's functions in Regulation 18, which are focused on the MOP's monitoring of the ETU and general operation of the wholesale electricity market:

Functions of the Electricity Market Oversight Panel

18. (1) The functions of the Electricity Market Oversight Panel are

(a) to monitor the general performance of the market administration functions of the Utility,
(b) to ensure the smooth operation of the wholesale electricity market,

(c) to review the operation of the wholesale electricity market and studies related to the development of the market,
(d) to review procedures, manuals and electricity market rules for the operation of the wholesale electricity market,
(e) to monitor pre-dispatch schedules,
(f) to resolve disputes referred to it by market participants in respect of transactions in the wholesale electricity market,
(g) to ensure the effective and consistent application by the Utility of the rules and standards of the wholesale electricity market,
(h) to ensure the long-term optimization of hydro-electricity supply sources in the country,
(i) make appropriate recommendations to the Commission in respect of the Panel's functions, and
(j) to perform any other function conferred on it by the Commission

(2) The Electricity Market Oversight Panel shall submit quarterly reports of its activities to the Commission and the Public Utilities Regulatory Commission on its assessment of the Utility's governance and the administration of the electricity market rules.

In addition to the omission of a statement conferring enforcement authority on the MOP, Regulation 34 of LI 1937 provides the ETU with the authority to enforce compliance with the market rules, market manual and system operation manual. In carrying out this enforcement authority, the ETU may impose a penalty or take other actions as described below:

Enforcement

34. (1) The Utility shall enforce compliance with the market rules, market manual and the system operation manual.

(2) The Utility may impose a penalty, issue a compliance order, directive, suspension order, revocation order or any other order to ensure compliance with the market rules, market manual and system operation manual.

While Rule 3.6.02 of the Market Rules specifically states that the ETU shall administer enforcement actions under the Market Rules at the direction of the MOP, a question exists as to whether Rule 3.6.01 conflicts with the authority granted the Utility under Regulation 34 of LI 1937. In addition, the specific omission of this activity from the functions of the MOP in Regulation 18 of LI 1937 coupled with the responsibility for the market monitoring authority as discussed below significantly extends the functions of the MOP. US Electricity market such as the Midwest ISO and PJM Interconnection are responsible for monitoring market participant compliance with market rules while an independent market monitor is retained to monitor the impacts of a market participants' behavior on the market.

Section 3.3 *et. seq.* provides the market rules applicable to Market Surveillance. Under these rules the MOP is identified as the responsible party for monitoring the performance of both market participants and the ETU. Assigning an independent entity or committee the responsibility of market monitoring is a generally accepted best practice in US energy markets. As discussed above, certain concerns regarding conflicts of interest and the MOP's direct oversight of market participant and ETU actions may arise given the composition of the MOP.

In addition to concerns related to conflicts of interest, the assignment of the market monitoring function to the MOP in the Market Rules seems somewhat inconsistent with Regulation 32 of LI 1937, which assigns this responsibility to the ETU. Regulation 32 of LI 1937 states:

> 32. (1) The Utility shall monitor and investigate the conduct of each market participant and the structure and performance of the wholesale electricity market including the conduct and activities that provide an indication of any of the following:
>
> (a) a breach of the electricity market rules,
> (b) non-compliance with the market manual or the system operation manual
> (c) the inefficient application of the market rules; and
> (d) an observed design flaw in the structure of the wholesale electricity market
>
> (2) The Utility shall evaluate market behavior in the wholesale electricity market in a manner necessary for the fulfillment of the objectives under sub regulation (1).

The express assignment of the responsibilities of market enforcement and market monitoring to the ETU in LI 1937 and subsequent assignment of this responsibility to the MOP in the DEMR appears to be in conflict. Given the MOP's oversight role throughout the DEMR, the assignment of these responsibilities to the MOP is not surprising; however, given the apparent difference between the functions and responsibilities of the MOP and ETU in LI 1937 and the DEMR.

In addition to the concerns regarding the proper authority of the MOP and ETU to carry out the functions as drafted in the Market Rules with respect to LI 1937 and the Energy Commission Act, the assignment of the market enforcement and market monitoring functions to the MOP may have additional impacts. Given the composition and function of the MOP as set forth in LI 1937, it appears that LI 1937 sought to establish a true oversight panel with a focus on reviewing the actions of the ETU and general operation of the market as provided in Regulation 16:

Establishment of Electricity Market Oversight Panel

16. (1) The Commission shall establish an Electricity Market Oversight Panel to supervise the administration and operation of the wholesale electricity market.

(2) The Electricity Market Oversight Panel shall carry out its functions and operations independently of the Utility.

(3) The Electricity Market Oversight Panel shall advise the Commission regarding the operation and administration of the wholesale electricity market.

While the MOP is not considered part of the ETU and is intended to carry out its functions independently of the ETU under Regulation 16, the functional implementation of the enforcement and monitoring activities should be monitored to determine whether the MOP is, in fact, carrying out its functions independent of the ETU. In addition, the extension of the market enforcement and market monitoring functions to the MOP under the DEMR may impact the resources (i.e., people and technology) necessary for the MOP to carry out these functions given the MOP's composition of representatives of market participants and industry who are responsible for functions within their respective companies.

In addition, the extended functions of the MOP under the DEMR may result in greater opportunities for conflicts of interest to arise in enforcement or monitoring actions. Furthermore, the performance of these functions will result in costs, which will most likely be recovered through the formula rate contemplated in Regulation 21 of LI 1937. In the US Markets, costs such as these are generally passed through to market participants as operating costs of the Independent System Operator or Regional Transmission Operator; however, the procurement of an independent market monitor is accomplished through a competitive biding process in an attempt to mitigate cost impacts. It is assumed that the Energy Commission's review of the expenses of the MOP will serve this mitigation function; however, the costs associated with carrying out these functions, whether by the ETU or MOP, may be significant.

With regard to penalties under the Market Rules, financial penalties and suspension or termination orders may be issued. For matters involving suspension and termination orders there is Energy Commission oversight; however, there does not appear to be a requirement that the Energy Commission approve a financial penalty assessed by the MOP. While there is ultimate review of MOP actions by the Energy Commission and PURC under Regulation LI 1937, it is required in the US that financial penalties such as those provided for under Section 3.6.19 of the Market Rules and LI 1937 be submitted to the Federal Energy Regulatory Commission for approval prior to the penalty being levied.

The DEMR governing the ETU's delegation of functions, powers and duties and establishment of panels to fulfill its functions, powers and duties are relatively brief. It appears that, in addition to the MOP, the DEMR contemplate the formation of at least two additional panels – the rule changes panel and the arbitration panel. The creation of panels or committees such as these is often necessary and commonplace in most markets. One key concern associated with the formation of panels is the manner in which they are established, either through democratic process or appointment, and the potential for conflicts of interest among the members. The brevity of Rule 1.9.01 does not address this issue:

Establishment of Panels

Rule 1.9.01 The *ETU* may establish such panels as it deems appropriate for the fulfilment of its functions, powers and duties under these *market rules.*

The provisions on delegation in Rule 1.9.02 below reference the *constituent documents,* which are defined as "means the memorandum and articles of association of the *ETU*".

Delegation of Duties by ETU

Rule 1.9.02 Subject to *Rule 1.9.01* the delegation by the ETU of its functions, powers and duties under these market rules shall be governed by the provisions of the *constituent documents*, provided that the *ETU* shall not delegate to any person any of the functions, powers or duties that are expressly reserved to the *ETU* in these *market rules.*

While Rule 1.9.02 specifically prohibits the ETU from delegating the functions, power or duties that are expressly reserved to the ETU in the DEMR, it is silent with regard to reference to the Grid Code, LI 1937 and the Energy Commission Act. More specifically, Regulation 3 (1) (a) of LI 1937 states that the Commission shall prepare the Grid Code, which shall govern the technical operations of the ETU. In addition, pursuant to the Part III of the Energy Commission Act, the ETU has certain obligations placed as a holder of a Transmission License. In addition, Regulation 10 of LI 1937 specifically states:

General functions

10. The Utility shall operate and administer a wholesale electricity market and perform the functions assigned to it under

    (a) the Act,
    (b) these Regulations,
    (c) the electricity market rules, and
    (d) the National Electricity Grid Code

As such, the limitation on the ETU's delegation of functions, powers or duties should be drafted in a manner that specifically prohibits delegation of functions, power or duties under the Energy Commission Act, LI 1937 and the Grid Code in addition to limitation on the delegation of functions, powers or duties that are expressly reserved to the ETU in the DEMR under Rule 1.9.02.

DEMR Rules 1.3.03 through 1.3.05, in reference to Regulation 8 of LI 1937, state that the Market Rules have the effect of a contract between the Market Participant and the ETU. In addition, Rule 1.3.04 specifically states that Each Market Participant and ETU shall be deemed to have entered into a contract with one another as provided below:

> **Rule 1.3.03** In accordance with Regulation 8 of the Electricity Regulations 2008 (LI 1937), the *market rules* have the effect of a contract between each *market participant* and the *ETU* and together with the *Grid Code* and other relevant regulations define their rights and obligation*s*.
>
> **Rule 1.3.04** Each *market participant* and the *ETU* shall be deemed to have entered into a contract with one another under which each *market participant* and the *ETU* agree to perform and observe the *market rules* so far as they are applicable to each *market participant* and the *ETU* as provided for in the *market rules*.
>
> **Rule 1.3.05** The *market rules* do not have the effect of a contract between *market participants*, the *ETU* and the *MOP,* rather they establish the administrative and regulatory authority of the *MOP* over the electricity market.

As discussed above, Market Rule 2.1.03 (c) references the execution of an *ETU/MP agreement*; however, such agreement is not provided as part of the rules. Pursuant to US regulation, 18 CFR §35.10 *et seq.*, standard form service agreements are required for services taken under rate schedules and tariffs similar to the Market Rules. These service agreements provide (often through incorporation by reference) the rights and obligations of the parties under the rate schedule or tariff and constitute a contract between the market participant and service provider, which in this case would be the ETU. The statements in Rule 1.3.03 and 1.3.04 appear to be intended to form a contract, or in the alternative of a specifically executed agreement, provide the Market Rules with the effect of a contract.

The limitation of liability provisions and indemnification provisions of Section 1.12 appear to be drafted in a manner that provides extended protection to the ETU, MOP and Market Participants for acts other than willful misconduct or negligent acts or omissions the first three months of the wholesale electricity market. Pursuant to the cessation provisions in Rules 1.12.36 through 1.12.43 this extended protection shall cease after the first three months of the market. While provisions providing extended protections to market operators and market participants during the start-up phase of a market are not uncommon, these provisions are generally focused on operational or bid / offer matters such as operating on cost-based bids and offers rather than limitations on liability. Upon cessation of the extended protections after the first three months of the market, the limitation of liability for the ETU, MOP and Market Participants focuses on limitation of indirect or consequential damages, loss of profit, contract or opportunity or *de minimis* amounts under GH₵5,000.

One issue to note with regard to the *force majeure* provisions of Section 1.12.20 through 1.12.33 is the required notice of providing the ETU and MOP notice that a Market Participant has invoked a *force majeure* event within two business days of the event. In general, a *force majeure* event would be of such a nature or magnitude that the ETU should be aware of the event and its impacts on the grid as it occurs or immediately thereafter, which would question the extended notice period of two business days. In addition, the *force majeure* provisions of Rule 1.12.33 are specific in their requirements that the ETU, MOP and Market Participants must perform their obligations under the Grid Code in addition to carrying out the requirements of operations during a *force majeure* event under the market rules.

The issue of contractual liability is addressed in DEMR Rules 1.12.34 – 1.12.35. These rules do not appear to contemplate the cessation of provisions of Rule 1.12.36 in that they apply to any agreement referred to under the Market Rules to which the ETU and Market Participant or the MOP and a Market Participant are parties.

> **Contractual Liability**
>
> **Rule 1.12.34** The liability and indemnification provisions of *Rule 1.12.01* to *Rule 1.12.03* and, where applicable, of any other *Rule* of these *market rules* other than this *Rule*, and the *force majeure provisions* shall apply to any agreement referred to in these *market rules* to which the *ETU* and a *market participant* or the *MOP* and a *market participant* are parties and to all acts or omissions of the *ETU* or the *MOP*, as the case may be, or the *market participant* in the execution or purported execution of any function, power or duty under such agreement.
>
> **Rule 1.12.35** In the event of an inconsistency between such liability, indemnification and *force majeure provisions* and the liability, indemnification and *force majeure provisions* of such agreement, the liability and indemnification provisions of *Rule 1.12.01* to *Rule 1.12.19* and, where applicable, of any other Section of these *market rules* other than *Rule 1.12.34* and *Rule 1.12.35*and the *force majeure provisions* shall prevail to the extent of the inconsistency.

A question is raised as to the applicability of these provisions in respect to the cessation of the reference provisions within after the first three months of the market. Clarification should be sought as to whether these provisions will apply to any agreements after the first three months of the market.

Rules 1.14.01 through 1.14.03 provide for the ETU and MOP's publication of bulletins providing interpretation of the market rules. An important note with regard to the publications of a bulletin by the ETU under the Rule 1.14.01 is that it is non-binding on the ETU pursuant to Rule 1.14.03.

See Appendix D for the specific references to Sections in the DEMR and discussions in respect of Dispute Resolution Process, Mediation, Arbitration and Rule Change Process.

Market Administration

Market Administration refers to the collective rules that allow non-discriminatory access to the transmission system.[29] In particular, the market rules, if they are to be non-discriminatory, must provide an unbiased methodology for allocating transmission capacity in real time. In order to accomplish this, the rules must spell out how dispatch, i.e. the real time balancing of supply and demand, will take place, including how the energy will be priced and settled. *It simply cannot be overstated that this is the most important aspect of the rules.*

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As discussed in Appendix B, the rules pertaining to the Market Administration function must address the four critical components of real time dispatch:

1. Scheduling. The Market Administrator must be able to obtain the information from grid-connected assets and the grid itself in order to assure the reliable balancing of real time supply and demand.
2. Commitment. The Rules must specify who has the responsibility – both physically and financially – for instructing units to start.
3. Dispatch. The Market Administrator will be required to coordinate all power flows on the network and they must do so in a non-discriminatory manner. Additionally the rules must state how the energy will be priced.
4. Ancillary Services. The Market Administrator will need to procure and periodically deploy ancillary services (e.g. frequency keeping, voltage support, black start, etc.) in order to maintain reliable grid operations. The rules must specify how this process will take place, how it is integrated into the dispatch process and how the services will be priced and paid for.

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As is detailed in Appendix B, there is no single "best practice" design for the market. Rather for each of the four activities listed above there are several different choices that can be made in order to best meet the needs of the market participants.[30] While there are a myriad of possible market designs that could qualify as "best practice", not every combination "works", i.e. the choices made on each of the four activities must be internally consistent. For example, it would be inconsistent for a market

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[29] Non-discriminatory access to the transmission system refers to the mechanism by which scarce transmission capacity is allocated to competing generators.

[30] Regarding the issue of the "needs of the market participants," one aspect that we have found to be critical is the existing state of the industry.

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design to not allow for generators to recover their fixed costs either through a capacity payment or in the energy market. Thus a market design that specifies that generators bids should be their marginal costs, should also logically provide a capacity payment to the generators.

Go to Appendix E for the specific references of the Sections in the DEMR and the related discussions on the subject.

Market Operations

Regarding the Scheduling Function, the DEMR specify that generators submit single part offers, i.e.GH¢/MWh to two decimal places that represent the "short run marginal cost" as defined below:

Rule 4.1.17 The price used in the dispatch of a generation registered facility shall reflect the *short run marginal cost* (SRMC) of the facility.

Rule 4.1.18 The *short run marginal cost* is the sum of the Variable Operating and Maintenance Costs and the Fuel Costs associated with the operation of the generating facility.

Rule 4.1.19 The equation for calculating the *SRMC for a generation registered facility* shall be as follows:

$$SRMC = H_R \, x \, F_C + F_{O\&M}$$

where: H_R is Heat Rate of generating facility in MMBTU per kWh

F_C is the cost of fuel in US$ per MMBTU

$F_{O\&M}$ is the fixed operation and maintenance cost per kWh

From these two rules it is not apparent how or even if a generator will be allowed to recover (1) the costs associated with start up, minimum run and shut down which are fixed and not variable costs and (2) the costs associated with the capital investment.

Rule 4.1.17 says that the price used in dispatch is the SRMC, and then Rules 4.1.18 and 4.1.19 provide opposing definitions of marginal cost. Rule 4.1.18 is the textbook (and correct) definition of marginal costs, i.e. that it is the change in variable costs. In comparison Rule 4.1.19 includes a fixed operation component which means it is no longer marginal cost. Thus these two rules are inconsistent. If in fact, the SRMC is allowed to include the fixed elements in Rule 4.1.19, then it is no longer the SRMC.

Deleted: Regardless of the starting point for generation and transmission infrastructure, the geographic location of the country or region, or the initial market design, virtually every electricity market in the world has either ended up or is moving to the design summarized in Figure 2.[31,32] Eventually this will be the underlying structure of the Ghana wholesale electricity market as well.
Market "administration" refers to two basic functions: (1) the balancing of energy in real time and (2) the settlement of financial responsibilities as a result of the balancing activities. ***<object><object>***As highlighted in Figure 2, at the heart of the market is the Security Constrained Economic Dispatch (SCED). The SCED is the "tool" the dispatcher uses to balance real-time energy flows and to accomplish re-dispatch that is necessary because of transmission constraints. In large part, electricity market design is an exercise in defining the rules around the SCED process. The SCED "process can be disaggregated into the following four components which constitute the basic functions of administering or operating the market:
1. **Scheduling** is the process of assuring enough generators are connected to the system, at appropriate locations to meet the load forecast, taking into consideration transmission limitations, transmission congestion, and meeting all the expected needs of generation based on Ancillary Services so that the system will reliably meet the load.
Providing the Dispatcher with a "schedule" is the primary way in which Market Participants give the Dispatch ... [1]

Deleted: ***It should be clear from the previous four bullet points that there is no single best market design. There are successful markets in operation based on each of the choices available. What is important, however, is that once the choices about what kind of market is desired, i.e. the choices made with respect to scheduling, commitment, dispatch and ancillary services, the resulting rules are consistent with those choices.***
Given the fundamental importance of the dispatch process to the operation and results of the market, we note that the primary source of information regarding dispatch is currently found in the National Electricity Grid Code and not the DEMR themselves. The result of this bifurcation of the rules pertaining to dispatch is incompleteness and inconsistency. In areas where a competitive market has been introduced it is common for dispatch rules to be contained in the market rules and for "grid codes" to contain the physical and technical standards by which the grid must be operated.
Market designs may differ in terms of who carries out the respective activity, e.g. generation units can self-commit or they can be instructed to be started by the Market Administrator, but the specific activity must be addressed by the rules. Specifically the market rules must address each of the following issues in order to define how the market will actually operate:
<#>Scheduling:
<#>Unbalanced Schedules ... [2]

Section 4.3 describes a market based on single part offers. In markets based on this design philosophy, generators must be allowed to include the return to capital along with the variable costs associated with operation and maintenance expenditures. If generators are only allowed to recover their variable costs, then they will lose money regardless of the level of their production. Therefore, we can assume that Rule 4.1.19 takes precedence over the language in Rule 4.1.18, which should be removed from the DEMR. The rules should also make clear that "fixed operation and maintenance cost" is meant to include the return to capital. However, the return to capital is not "fixed", it varies with the value of the asset as well as the cost of capital and the "SRMC" for a generation registered facility should be allowed to vary accordingly.

In addition, the offers from generators must be allowed to include the costs associated with start-up, shut-down and minimum run. The alternative to single part offers are either two or three part offers. With two part offers, the generator offer consists of the MC of production and the start-up and no load costs. A three-part offer would add the load necessary for minimum run operation. There is nothing inherently better or worse about a market based on single, two or three-part offering. The choice does however, have a significant effect on the structure of other design elements. For example, where the market design allows for the dispatcher to start generation units for reliability purposes the objective function for the commitment decision is to minimize the cost of acquiring the capacity – a task made easier when the design is based on two or three-part offers. The task of monitoring offers with regard to monopoly behavior is more difficult under a single part regime because the generators must be allowed to include the return to capital which may be different for every generator connected to the system.

The DEMR do not specify how many tranches a generator can offer. Normally we would expect that regardless of the technology, the cost of generation and hence the offer curve for a generator will be monotonically non-decreasing[33] and this should be reflected in the rules governing offering behavior as well. Therefore, we would recommend that a generator's offer curve consist of up to ten tranches of price/quantity pairs that must be monotonically non-decreasing.

The Rules and the Appendices are silent on how the ETU will transform the individual offer curves into an aggregate supply curve for purpose of running the Market Clearing Engine.

Regarding the Commitment Function, in their current state the DEMR do not provide a mechanism for the Dispatcher to commit generation capacity. Presumably the Dispatcher could rely on Article 10.95 of the National Electricity Grid Code to order plants to start. However, this presupposes that an Emergency Condition has already

[33] A Monotonically non-decreasing offer curve means that the marginal cost of additional megawatts is either equivalent or greater than the cost of previous megawatts.

Commented [A9]: Operating and maintenance cost does NOT USUALLY include return to capital

Commented [RM10]: Completely agree. But the rules, as written, do not allow for the generator to be paid for capacity UNLESS we "broaden" the definition of O&M costs.

Commented [A11]: Could you please explain it.

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been declared. In other words, like the National Electricity Market of Singapore, the market created by the DEMR is a based on self-commitment.

Markets in the United States and elsewhere have typically included in their design the ability for the Dispatcher to commit, i.e. bring capacity on line, generation units prior to real time in order to avoid an emergency.

Regarding the Dispatch Function, while not inherently "wrong" the rules are not nearly complete enough to provide real guidance to either the Dispatcher or to Market Participants. The underlying assumption of a constraint-free grid permeates this section – as it does the entire rule set – and makes it impossible to form an accurate depiction of how the market is supposed to work. Unlike Singapore, the Ghanaian electricity grid has constraints and the rules provide no insight into how those constraints will be managed when electricity is flowing.

There is no explicit mention of how losses are to be treated in either the dispatch process or in the final pricing. The Rules use the term "fixed losses", but in actuality, losses vary according to distance of generation relative to the load. We do not know whether the Market Clearing Engine relies on fixed loss factors or whether it is based on variable factors. Importantly we do not know how losses will be priced – will the MCE price on the basis of marginal or average losses?

Likewise, the DEMR do not specify how the Market Clearing Engine is to determine the amount of reserves. There is no discussion of whether energy and reserves are co-optimized or whether reserves are simply an "add-on" to the demand forecast.

While the treatment of losses and reserves represent serious flaws, the most significant omission is that the rules provide absolutely no detail on how the Dispatcher is to accomplish re-dispatch, i.e. how will the Dispatcher dispatch out-of-merit generation to solve a transmission constraint. It is not even clear whether the Dispatcher would be allowed to re-dispatch the system.

With respect to calculating the price, the rules are similarly silent when it comes to the *fact* that every time there is a constraint there will be more than one generating unit that is marginal and hence there will be more than one System Marginal Price. A further flaw in the creation of the Uniform Ghana Electricity Price is that it is based on the short run marginal cost of generation and completely ignores the price effect that will necessarily be caused by transmission constraints. In this regard the rules are inconsistent.

Regarding the procurement and deployment of Ancillary Services, the DEMR provide for the Dispatcher to acquire spinning and "standing reserves" through Rules 4.1.20 – 4.1.22:

Procurement and Dispatch of Reserves and Regulation in the WEM

Spinning Reserves (Regulation) Procurement

Rule 4.1.20 Twenty percent (20%) of the operating capacity of each dispatchable generation registered facility will be allocated to spinning reserve.

Procurement of Standing Reserves

Rule 4.1.21 Standing Reserve is to provide standing reserves to the relevant real time market by a generation registered facility at its market network node in a dispatch period

Rule 4.1.22 Standing Reserves shall be procured based on:

(a) availability during each dispatch period;
(b) cost; and
(c) response time

We note that forcing each generation facility to allocate 20% of their operating capacity for spinning reserve is a substantial reserve margin and above any standard as applied in North America. Certainly having 20% of the available capacity "held back" will provide the Dispatcher with a substantial margin to manage contingencies.

The Grid Code actually provides a much clearer and definitive description of reserves, starting with the

Types of Reserves

Art 9.20 *– Operating Reserves are that generation capability above firm system demand that are required to meet the standards of an adequately responsive system for regulation, load forecasting error, mismatch between generation and demand, equipment forced outages and scheduled outages. Operating reserves consist of spinning reserves and non-spinning reserves.*

Art 9.21 *– Spinning Reserves consist of the unloaded generation capacity, which is synchronized and ready to automatically serve additional demand without human intervention in order to arrest a drop of system frequency due to an instantaneous mismatch between generation and demand. It shall include and consist primarily of the additional output from currently operating generating plant that is realizable in real time and can be provided steadily for at least one hour.*

Art 9.22 *– A Non-Spinning Reserve is that generation capability not operating or synchronized to the system but which is available to serve demand within thirty minutes of being requested so to do. Specifically, a Non-spinning reserve shall comprise the steady output available from a generating unit that can be synchronized to the NITS and* *loaded up within the specified period to respond to an unexpected demand increase or loss of generation or transmission capacity.*

It is not clear whether it was an oversight or a mistake that the DEMR did not retain this language, i.e. the use of the term "Operating Reserves" which contains both Spinning and Non-Spinning Reserves, but it leads to confusion. Moreover, the Grid Code does not make use of the term "standing reserve as do with the DEMR. As a result it is not clear whether the 20% requirement in Rule 4.1.20 is meant to include the amount to be used for spin and non-spin or just the former.

The Grid Code defines the reasons why the Dispatcher can deploy spinning reserves, i.e. the uses of spinning reserves, and they appear to be much broader than the simple regulation or frequency-keeping implied by Art9.21 above. In particular, Art9.24 below plainly states that Spinning Reserve is to be used as standby or synchronized reserve:

Art 9.24 *–The Spinning Reserve at any time shall be large enough to enable the grid withstand any one of the following events:*

(a) *the loss of the generating unit currently producing the highest amount of power within the NITS, or*
(b) *the loss of generation capacity that could result from any single transmission equipment failure, fault or other contingency, or*
(c) *the loss of any power in-feed from an interconnected system, whichever is the largest*

Art 9.25 *– The ETU shall allocate and distribute the required Spinning Reserves among the generating units operating within the NITS such that the grid is able to withstand any single contingency.*

How the ETU reconciles the apparent inconsistency between Art9.21 and Art9.24 is important to how the market will operate. However we note that the DEMR could possibly be interpreted as assuming the narrow definition of spinning reserves. In particular the heading for Rules 4.1.20 – 4.1.22 is Spinning Reserves (Regulation) Procurement.

If the Dispatcher adheres to the Grid Code, then they cannot use Spinning Reserves to provide voltage and reactive support. Voltage support is usually provided by reducing MW output and increasing MVAR output. Reduced MW output is replaced through a re-dispatch of the system. This does not usually occur within a timeframe small enough to require reserve activation. Instead according to the Grid Code the ETU is required to procure reactive support separate from procuring spinning and non-spinning reserves:

Voltage Management

> ***Art 9.11*** *–The ETU, in operating the transmission system, shall schedule generating plant reactive power outputs and procure reactive compensation as necessary to maintain the voltages at all NITS nodes and substations within established limits, as stipulated in Technical Schedule TS-L.*
>
> ***Art 9.12*** *– Each generating plant shall be capable of continuous operation within the stipulated power factor range to support voltages under normal and contingency conditions.*

Perhaps, standing reserves are to be used for reactive support but the rules provide no insight into precisely what standing reserves are to be used for and as previously noted the Grid Code has no such term as "standing reserves". Assuming that standing reserve is not a synonym for reactive support, the market rules provide no mechanism for the procurement or even the inclusion of reactive support in the scheduling and dispatch process.

Go to Appendix F for the specific reference to the Section(s) in the DEMR and the related discussions on the subject.

Market Settlements

Settlement rules are best thought of as the mirror image, albeit financial, of the rules governing Market Operation. The settlement rules contained in the DEMR are a relatively accurate reflection of the market design described in Section 4. To the extent that there are "issues" with the settlement rules it is because the market design is itself flawed.

Conclusions

Legal and Regulatory Framework

In general, the legal and regulatory framework underlying the development of the wholesale electricity market is consistent with the principles of successful wholesale electricity markets around the world. The drafting and implementation of Market Rules in a manner that is consistent with the underlying legislation directing the wholesale electricity market and Commission policy is imperative to maintain the solid legal and regulatory framework upon which it is based. As discussed in greater detail below, a key area of the DEMR that should be considered is the role of the MOP throughout the draft rules. Pursuant to LI 1937, the MOP has been created to provide oversight of the ETU in its implementation of the Market Rules. To the extent that the DEMR extend the role of the MOP into activities reserved to the ETU the potential for conflicts of interest and inconsistency with the underlying legislation. In addition, the ability of the MOP to carry out additional functions given its members' obligations to their respective companies may require additional resources or compromise the quality of the services of the MOP contemplated by LI 1937.

Market Participation

With respect to sections of the DEMR that relate to:

- Membership and market participant status,
- Classes of participation and licensing,
- Rights of participants,
- Oversight of participant conduct (e.g. market enforcement, market monitoring, and penalties)
- Contractual force, liability and indemnification,

as discussed in the Findings and Issues section, there are not only a number of inconsistencies between the DEMR and the legislation, but the Rules themselves are incomplete.

Market Administration

Market Operations

Regarding the scheduling function we are concerned that based on the rules governing generator offers, it is not clear how generation facilities will recover their start up, minimum run or shut down costs. Nor is it clear whether the rules will allow for the recovery of the fixed capital costs of investment.

The dispatch rules are incomplete and based on an incorrect assumption. There needs to be specific rules regarding how the Market Clearing Engine and the pricing algorithm treat losses and reserves. But most importantly the dispatch rules need to provide guidelines for how re-dispatch will be physically accomplished and how it will be reflected in the locational/nodal prices, that is - reserve requirements must be recognized as a constraint, solved for and priced as such. The incompleteness is perhaps due to the fact that most of the rules regarding dispatch and reserves are contained in the Grid Code.

Moreover, with respect to Ancillary Services, there appear to be inconsistencies within both the Grid Code and the DEMR as well as between the Grid Code and the DEMR. In its current state, the proposed structure is unlikely to reduce the costs of reliability and given the lack of specificity/precision regarding the deployment of ancillary services it is likely to introduce uncertainty and hence higher prices into the energy market itself. Follow up to Appendix G for specific discussions in respect of the relationship of DEMR to Financial Market Outcomes, Reserve Capacity Rules and Contract Administration

Market Settlements

Since the settlement rules are simply a translation of the market design into financial terms, the same conclusions that were reached with respect to market operations are applicable to market settlements. Follow up to Appendix H for discussions in respect of specific references to Section(s) in the DEMR on Market Settlements

SECTION C: RECOMMENDATIONS

Legal and Regulatory Framework

1. To the extent that certain generation resources elect not to participate in the wholesale electricity market the management of constraints on the transmission system and deliverability of participating generation resources to load may be impacted. In this instance, it is recommended that VRA seek confirmation from the Commission that participation in the electricity market is required by all generation and load meeting a threshold criterion (i.e., all generation and load above 10MW). In the absence of this confirmation, it is recommended that VRA identify generation and load that may opt not to participate in the electricity market in an effort to determine whether the nonparticipation by these parties would create operational issues or increase the difficulty of the ETU's ability to manage the grid.

2. In order to address the prohibition against bilateral contracting of the hydro-electric dams, it is recommended that VRA petition the Commission for the ability to enter into bilateral contracts, at least for a portion of its capacity. In the alternative, VRA should seek greater detail in the market settlement rules to ensure that the potential exposure to an unfavorable spot price is known and can be mitigated.

3. It is recommended that VRA seek clarification of the MOP's role under the legislation and apply this clarification to subsequent drafts of the DEMR to ensure the MOP's role is not extended beyond that intended by LI 1937.

Market Participation

1. As discussed in the Issues and Findings section, inconsistencies between the DEMR and the relevant legislation need to be resolved as do areas where the DEMR are incomplete.

2. If VRA chooses to engage an agent to perform any of its obligations under the Market Rules, it is recommended that VRA address the agent's liability for actions under the engagement agreement or contract with the agent as any actions of the agent will be viewed as the actions of VRA by the ETU.

3. it is recommended that clarification be sought with regard to the ETU's authority to assign the market enforcement (i.e., oversight of market participant compliance with the market rules) and market monitoring responsibilities to the MOP as provided in the Market Rules.

Market Administration

Market Operations

The fundamental flaws contained in Section 4 require that the market design be re-thought. Our specific recommendations are that:

1. *Section 4: Market Operation* and the relevant Appendices of the DEMR comprise the foundation of the Market Administration function are:

    a. based on the incorrect premise that the Ghanaian electricity network is unconstrained,
    b. incomplete in that they do not define how re-dispatch will occur,
    c. inconsistent with the National Electricity Grid Code

    and must be rewritten. Other sections or components of the rules, while important, e.g. governance, are secondary in importance to the rules of how real time power flows will be balanced and priced.

2. The re-drafting of Section 4 should pay particular attention to:

    a. Pricing for load,
    b. Whether the market should be a self-commitment or central commitment market,
    c. Recovery of start up, shut down and minimum run costs,
    d. Defining the procedures/actions taken by the Market Administrator within the hour of real time operations,
    e. Payment for providing reserve, and
    f. How transmission losses will be priced.

3. The re-drafting of Section 4 should be done in a collaborative stakeholder process to ensure that all possibilities are considered and discussed.

4. Once Section 4 has been re-drafted and has the approval of the industry, work should be undertaken to re-draft or edit the remaining sections of the DEMR to ensure they are consistent with the new language and paradigm.

5. A process should be instituted to ensure that the eventual market rules and the National Electricity Grid Code are consistent and aligned.

Market Settlement

The rewriting of Section 4 will necessitate that Section 5 governing settlements will need to be rewritten to reflect the new market design elements.

APPENDICES

APPENDIX A: Three-Node Model

As was stated in the previous section, the physical characteristics of electricity necessarily mean that the transmission system cannot be perfectly "rationed" prior to real time in as much as the capacity of the transmission system at any point in time cannot be known with certainty until power is actually flowing. Moreover, the capacity of the system is not simply a function of the physical infrastructure of generation, and transmission facilities and load, but also a result of the decisions made by the dispatcher in matching supply and demand. Therefore, the starting point of good market design is with the dispatch function itself because this is the foundation of all wholesale electricity markets.

In effect, the electricity market rules can be thought of as a set of instructions, rules and processes for how the system will be dispatched. Every electricity market that has tried to ignore this basic fact has met with failure and the rules have had to be changed. The reason for this importance is due to the unique characteristics of electricity. In particular, electricity cannot be stored in meaningful quantities, which means that current supply must equal current demand, and electricity will always follow the laws of physics. Market rules that do not reflect these fundamental characteristics have always and will always result in the failure of the market. Since the laws of physics cannot be ignored or altered, market rules that are not firmly based in the reality of electricity cannot support a workably competitive electricity market. In other words, good market design begins with reliable *real time* operation of the system. Without a reliable system there can be no market.

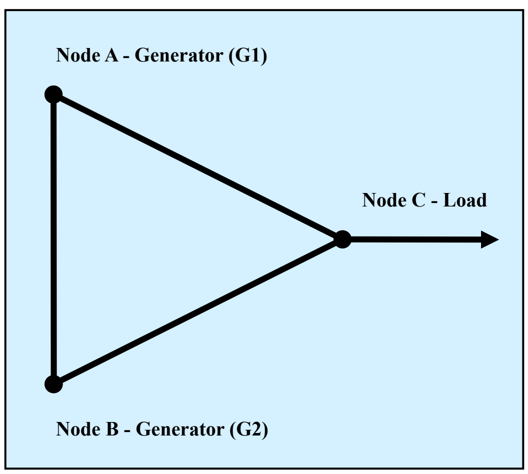

Figure A1: Simple Electrical System – No Transmission Constraints

It is useful to develop a context or paradigm to view the rules through. We begin with the simplest possible interconnect system; three nodes connecting two generators and one load. The system is shown in Figure A1. The generators are located at Nodes A and B (G1 and G2 respectively) and the load is located at Node C. To keep things as simple as possible we assume the transmission lines, AB, BC, and AC are identical length, size and there are no losses when electricity is flowing.

In this abstract system, with infinite and lossless transmission capacity load can be served either from G1 or G2. We can create a simple Economic Merit Order[34] from the short run marginal costs[35] of each generator.

This simplistic model doesn't allow for much understanding or analysis of the problems facing the system operator in real time. In this hypothetical world the job of the job of system operator would be pretty easy. Simply choose the cheapest generator necessary to meet the load.

However, if we relax just a single assumption regarding the transmission system we can start to use this model to help guide us through the proposed rules. Specifically we will assume there is a line limit on the transmission line between A and C. A line limit is an example of a transmission constraint. In reality there are many other transmission constraints that the system operator must take into consideration when matching actual/physical supply and demand in real time.

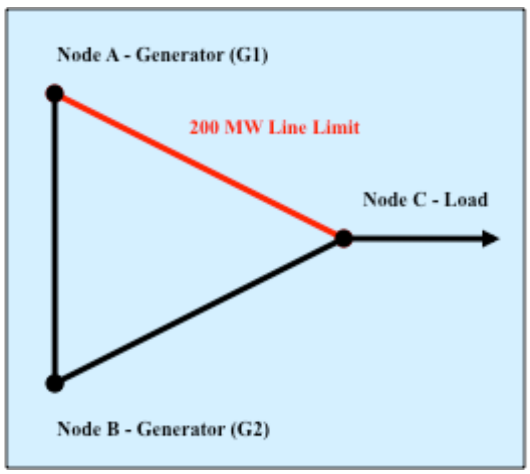

Figure A2: Simple Electrical System – Single Transmission Constraint

In Figure A2, we relax the assumption of unlimited transmission capacity by introducing a thermal constraint on AC. Specifically the line now has a 200 MW limit, i.e. it cannot transmit more than 200 MW of power from Node A to Node C or vice versa.

We can now use this model to derive some conclusions regarding dispatching the system. First, if we assume that load at Node C is 300 MW then either G1 or G2 is capable of supplying the load. Figure AC2 shows the situation when G1 produces 300 MW. In this case, 200MW from G1 will flow along AC to the load at Node C, while 100MW will flow along AB and then BC to the load at Node C. If G2 produced the entire amount, then 200MW would flow along BC, with the other 100MW

[34]Per Rule 4.1.15 of the Draft Market Rules
[35]Per Rule 4.1.17.

flowing from BA to BC. The 1/3 "relationship" between the transmission lines is a product of our assumption that the lines are of equal length and Kirchoff's Law.

Suppose instead that load at Node C was not 300MW but 600MW. Note first that G1 cannot supply the entire load. If G1 produces 600MW, 2/3 or 400MW will flow along AC which will be a violation of the line limit and AC will burn up. G2 on the other hand, can supply the entire load. As shown in Figure AC3, if G2 produces 600MW, 400MW will flow along BC and the remaining 200MW will follow BA to AC without violating the 200MW line limit

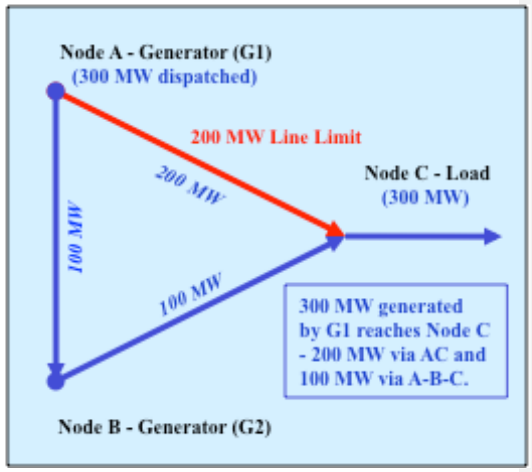

Figure A3: Simple Electrical System – Single Transmission Constraint, 300MW of System Load

Figures A3 and A4 can be used to develop some insight into so-called physical "rights" to transmission capacity.[36] In the natural gas industry, it is normal to purchase pipeline "capacity" in order to move gas from a source to a sink.

Typically the producer or shipper will obtain the necessary transmission capacity and then schedule their gas using the physical transmission rights, i.e. they own the right to use a specific amount of the pipeline. The simple model developed here shows the fallacy of this paradigm when applied to electricity transmission. In electricity, unlike natural gas, the capacity of the network depends upon the load and the location of the generation used to meet the load. In Figure A3 the "capacity" was 300MW if G1 is used to meet the load, while in Figure A4 the "capacity" was 600MW if G2 is used to meet the load.

[36]In the United States it was initially assumed, incorrectly, that the physical capacity of the transmission system was static and knowable, i.e. like that of a natural gas pipeline network. This led to the creation of "physical transmission rights" for the electricity system that users of the transmission system had to acquire in order to schedule and use the network.

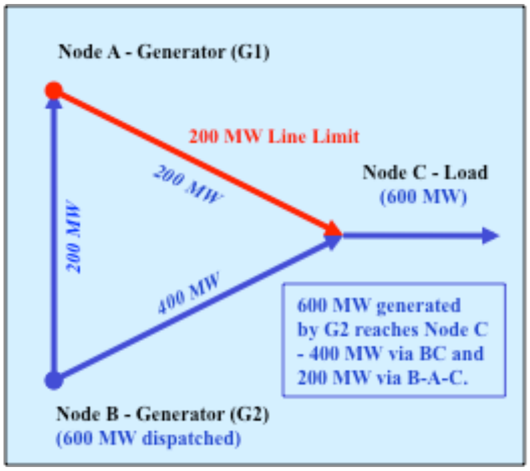

Figure A4: Simple Electrical System – Single Transmission Constraint, 600MW of System Load

Now let's assume that the short run marginal cost of G1 is $20 and that of G2 is $30 and both have unlimited generating capacity. If the load at C is 270MW then the optimal generation dispatch would be for G1 to produce all of the output (total cost would be 270MW * $20 = $5,400.

Figure A5 provides the detail of how the power would actually flow from G1 to Node C. In this case, the *system-wide price* would be $20. That is everybody on the system would either pay in the case of load or be paid in the case of G1 $20. G2 would receive no revenue since they did not produce any electricity.

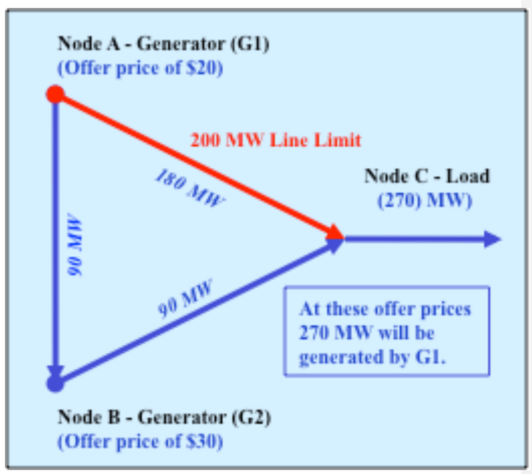

Figure A5: Simple Electrical System – Single Transmission Constraint, 270MW of System Load and SRMC

But what happens if load rises from 270MW to 360MW. If the transmission system is unconstrained, having G1 produce all 360MW would be the least cost option. But the existence of the line limit on AC means that the system will have to be **re-dispatched**.

Furthermore, since we saw in Figure A3 the most that G1 can produce is 300MW, it might *seem* optimal to have G1 produce 300MW, while G2 produces the remaining 60MW. Total cost under this scenario would be: (300MW * $20) + (60MW * $30) = $7,800. However, if G1 produces 300MW then there is no available capacity on AC. Thus when G2 produces 60MW and 1/3 of that output flows on AC, the line limit will have been exceeded (200W from G1 and 20MW from G2). So while, this may be a least cost solution, it is not a feasible solution!

Rather than dispatch according to the simple Economic Merit Order, the system operator is going to have to ***re-dispatch***, i.e. the dispatcher is going to have to change the least cost level of output because it does not respect the transmission constraints in the system. Given the offer prices and the system, the least cost solution will be when G1 produces 240MW and G2 produces 120MW. The total cost will be (240MW * $20) + (120MW * $30) = $8,400, which is $600 more than the "unconstrained" solution. Figures A6 shows the final solution.

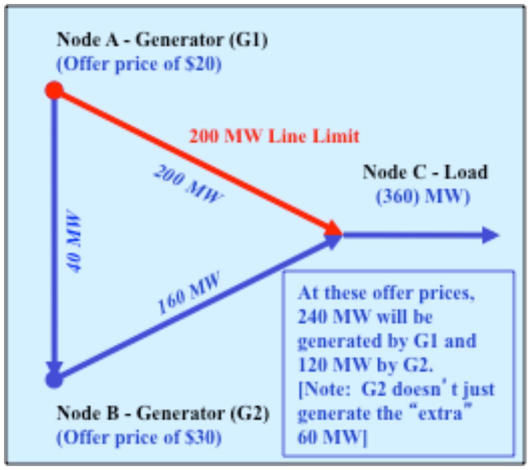

Figure A6: Simple Electrical System – Single Transmission Constraint, 360MW of System Load, Optimal Dispatch

Assume the system dispatcher started with the assumption that the cheapest generator (G1) was going to produce all of the power necessary to serve the load, i.e. 360MW. But he/she knows that will cause AC to have 240MW of power flowing across it, when the constraint is 200MW. So the operator has to relieve 40MW of flow across AC while keeping the lights on at C. Suppose it was possible for the operator to sequentially solve this problem, i.e. they start with the cheapest solution, regardless of constraints, and then find a solution that is least cost while not violating the constraints, i.e. they determine the optimal dispatch solution. For every MW reduction in output by G1, the operator in effect, "buys" 2/3MW of space on AC, which then allows him to "buy" 2MW of output from G2. In this way the optimal dispatch will occur when G1 and G2 are producing 240MW and 120MW respectively. This solution is "optimal" because it minimizes the cost of meeting the demand without violating the constraint. No other solution will achieve this result. Suppose for example, the dispatcher chose instead to use 238MW from G1 and 122MW from G2, then total production costs for this solution would be $20 higher at $8,420. Alternatively, suppose they chose G1 and G2 to produce 241MW and 119MW respectively. This would lower production costs to $8,390 but would cause the flow on AC to be 200.33 and would violate the line limit. Figure A7 provides a

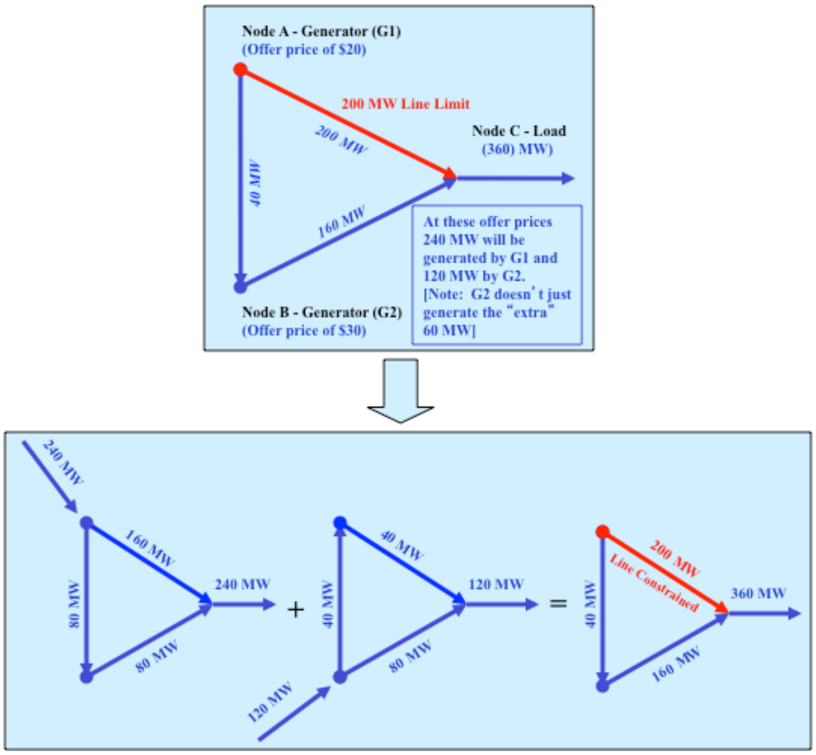

Figure A7: Simple Electrical System – Single Transmission Constraint, 360 MW of System Load, Power Flows Under Optimal Dispatch

disaggregated view of the power flows from both G1 and G2 under the optimal solution.

Given the optimal dispatch, we can use the model to evaluate different potential pricing methodologies. Suppose that G1 and G2 were both owned by the same company. Generation would then be a monopoly and presumably regulated and we could use *average cost pricing* and simply divide the total production costs by the number of megawatts to find the average production cost and use that as our price. In this example that would be: $8,400/360MW = $23.33. In this example, our interest is not in determining a "price" as much as it is to ensure the generator gets cost recovery. However, if a single company does not own G1 and G2, i.e. they are competitors, average cost pricing will not "work." Under this methodology, the "price" did not cover G2's marginal cost ($23.33 versus $30), so why would G2 produce any electricity if they knew they were going to lose money on every megawatt.

Under an average pricing regime – which is what is used to regulate declining marginal cost industries like electricity – when the system operator calls for G2 to produce they will not respond, and the load will not be served. Thus, in a competitive market we cannot use average cost pricing without providing an extra payment to G2, the generator whose marginal cost is above the average cost.

Alternatively, we could use a simple Economic Merit Order to determine the highest priced generator needed to satisfy demand and create a system-wide "market" clearing price. This would mean that G2 at $30/MW would set the price. The total cost to consumers would be $30 * 360MW = $10,800. Like average cost pricing, there is a certain appeal to the simplicity of having a single price. However, as will be shown with the next methodology, that simplicity comes at the cost of masking the complexity of electricity transmission and dispatch.

A third alternative is to find the price that reflects what actually took place including the steps the dispatcher needed to take in order to match supply and demand while recognizing the constraints. This is called *marginal cost pricing* and we need to calculate the *marginal cost of the next megawatt at each node.*

Suppose that load at C was 361MW rather than 360MW. We know how much G1 and G2 produce when load is 360MW, but how would the dispatcher acquire one more MW. He/she would reduce G1 by 1MW which saves $20 and then increase G2 by 2MW (1MW to make up for the reduction in G1's output and 1MW to meet the added load) which would cost $60, i.e. 2MW * $30. Thus the marginal price at Node C, when load is 360 is: (-1 * $20) + (2 * $30) = $40. We can do the same analysis at the other two nodes and determine that prices are $20 at A and $30 at B. Thus the price that reflects the actual dispatch is not a simple single, system-wide price but rather three prices, one for each node:

- Price at Node A = $20,
- Price at Node B = $30,
- Price at Node C = $40.

It is useful to reflect on these prices and in particular the information that is being conveyed. For consumers at Node C, an extra MW of demand will require the dispatcher to reduce output from G1 by 1 unit and increase G2 by 2 units. Given the assumed marginal costs of G1 and G2 the cost is $40. Under average cost pricing the price would be $23.33 and under the simple highest generator running approach the price would be $30. In either of these cases, consumers would pay a price that is lower than the actual cost – *given the transmission system!* In other words the latter two pricing mechanisms do not accurately reflect the reality of the transmission system and the required actions of the dispatcher to match supply and demand.

Under the marginal cost pricing example, generators will receive the price at their node times the amount of output they produced or $8,400 in revenue (G1 will receive $20 * 240MW = $4,800 and G2 will receive $30 * 120MW = $3,600) and the load will pay $14,400 (360MW * $40/MW). In this example, the binding transmission constraint leads to three separate and distinct prices and leads to the creation of a $6,000 settlement surplus. It is imperative that neither the Gridco nor the Poolco receive this surplus. The surplus is the direct result of a transmission constraint and the Gridco should not be rewarded for having a highly constrained transmission system. Likewise the Poolco should not be financially rewarded for using a dispatch that maximizes rather than minimizes the surplus created from transmission constraints.

The surplus should be returned to the customers in some manner. Since the surplus arises from the existence of transmission constraints the usual method for returning the surplus is through financial transmission rights (FTR). An FTR pays the owner the difference in prices between two nodes on the system. Thus in our example, the owner of an FTR from A to C would receive $20 for every 1MW FTR they owned. There are alternative methods for returning the surplus.

Returning to the different pricing methodologies, notice that under the simple Economic Merit Order pricing methodology, the actions of the dispatcher in recognizing and then managing the constraint is not reflected in the price. The $30 price reflects only the cost of generation. But in reality, the existence of the 200MW line limit on AC means that an additional megawatt of demand requires ***re-dispatch***. That is, an additional megawatt of demand requires the dispatcher to back G1 down by 1 megawatt and ramp G2 up by 2 megawatts. Thus the true cost of an additional megawatt of load at Node C is not $30, but rather $40. If we adopt the simple Economic Merit Order approach to pricing we will be undervaluing the effect of the constraint and, as a result, over encouraging the use of electricity. Moreover, we will not be sending the appropriate investment or consumption signals to the market.

In conclusion, if a system has no transmission constraints (e.g. thermal, voltage, stability, etc.) then there is no real need for a system operator to coordinate power flows and the market rules can, and should, be quite simple. However, the assumption or the belief that a particular system has no transmission constraints has always turned out to be false in other market design and implementation processes. In many cases, existing constraints are well known and managed prior to real time, i.e. through the scheduling or commitment process. That the constraints in a particular system may not have shown up historically in real time simply means that the behavior of participants has been modified over time because they know the constraints will arise. And because in most cases the participants are either regulated monopolists or government entities the behavior of participants is different than it is in a competitive market.

APPENDIX B: Electricity Market Design

With respect to the basic tenets of good electricity market design the industry has, over the past 10-15 years, converged around a few central tenets that must be in place if the market is going to work. This convergence has come across both geographic boundaries as well as initial conditions. That is, it does not matter whether a system is based in Asia, North America or Europe or if it has a preponderance of hydro or thermal based generation – the basic tenets of good electricity market design are the same.

Successful electricity market designs:

1. Are based on the physical reality of electricity, i.e. nodal and not zonal congestion management,

2. Provide the correct economic incentives to the participants so that their actions are consistent with least cost reliable dispatch,

3. Clearly define how and when non-market, i.e. command-and-control, interventions by the dispatcher will take place,

4. Either directly provide or indirectly allow for the development of efficient financial risk management instruments for price volatility arising from constraints and

5. Protect the market from the exercise of market power.

Every electricity market must address by whom and how each of these five tasks will be performed.

Regardless of the starting point for generation and transmission infrastructure, the geographic location of the country or region, or the initial market design, virtually every electricity market in the world has either ended up or is moving to the design summarized in Figure 2.[37],[38]

As highlighted in Figure 2, the heart of the market is the Security Constrained Economic Dispatch (SCED). The SCED is the "tool" the dispatcher uses to balance real-time energy flows and to accomplish re-dispatch that is necessary because of transmission constraints. In large part, electricity market design is an exercise in defining the rules around the SCED process. The SCED "process can be disaggregated into the following four components:

[37]Chandley, John and William W. Hogan, "Electricity Market Reform: APPA's Journey Down the Wrong Path," April 2009, p. 27.

[38]The "RTO" or Regional Transmission Operator is the North American term for system operator or market administrator. In the Ghana context, Gridco will perform the functions of the RTO.

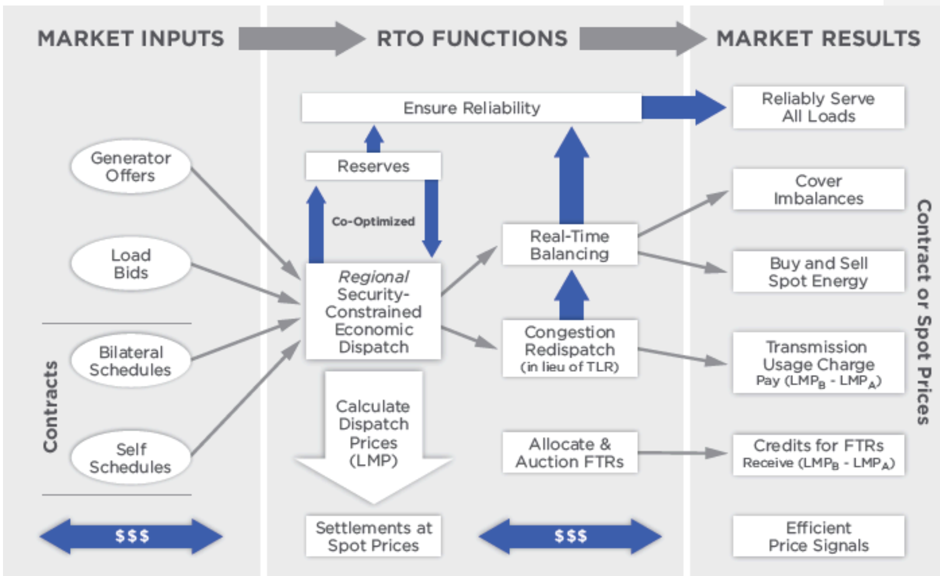

Figure 2: Basic Elements of Successful Electricity Market Design.

1. Scheduling is the process of assuring enough generators are connected to the system, at appropriate locations to meet the load forecast, taking into consideration transmission limitations, transmission congestion, and meeting all the expected needs of generation based on Ancillary Services so that the system will reliably meet the load.

> Providing the Dispatcher with a "schedule" is the primary way in which Market Participants give the Dispatcher information about what they intend to do in real time. The schedules can be either "balanced" or "unbalanced" depending upon the Market Rules. A "balanced" schedule is one in which expected real time generation and load are equal. Requiring balanced schedules is an attempt to force participants to use bilateral contracting rather than rely on the spot market and have exposure to spot electricity prices. Accordingly markets based on balanced schedules typically apply a financial premium or penalty for deviations to schedules that must be accommodated in the real time. Current examples of markets that are based on balanced schedules include the Southwest Power Pool's Energy Imbalance Market and the British Electricity Trading Transmission Arrangements. In contrast, unbalanced schedules simply require market participants, primarily generators, to supply bids/offers for the electricity they expect to buy or sell in real time. New Zealand, Singapore, PJM, MISO, ISO-NE, CAISO, ERCOT, and

NYISO are all examples of markets based on unbalanced schedules. It is common for the design to provide a financial incentive for Market Participants to provide accurate information by including a Day Ahead Market where the participants can hedge their exposure to real time price volatility. There are no rules prohibiting a participant submitting a "balanced" schedule even if they are not required to do so.

In Figure 2, the scheduling process is the activities taking place on the far left hand side of the diagram under the category entitled "market inputs."

2. **Commitment** is the process of starting units before real time that are expected to be running in real time. Markets can be based on self-commitment, central commitment or a mixture of both. In self-commitment markets which is what is proposed in the DEMR, generators self-commit their units, while in central commitment markets, generation is centrally committed by the Market Administrator/Operator. In self-commitment markets, generators must be able to recover the costs incurred with starting up, shutting down and running at minimum load through their offers (single part offers). In comparison, central commitment markets require that start up, shut down and minimum run costs be excluded from the energy component of the offer (three part offers).

3. **Dispatch** is the process whereby real time electricity is balanced, i.e. the supply and demand of electricity is always equal. The physical laws of electricity require that dispatch be performed on a gross or aggregate basis and at the nodal level. That is, in order to have a reliable system, the dispatcher must coordinate all power flows and not just a subset, i.e. both bilateral and spot energy production and purchases must be coordinated together. While physical dispatch must be nodal and take into consideration all electricity flows, the rules can dictate any number of different pricing mechanisms, i.e. nodal or zonal, pay-as-bid or market clearing, etc.

4. **Ancillary services** are required elements of an electricity market because the price mechanism cannot allocate resources in the time frame necessary to maintain reliability. For example, if a generating unit trips, reserves must be available immediately in order to arrest a frequency decline that could endanger the entire grid. Without reserves (an example of an ancillary service) the Market Administrator would have to re-run the Market Clearing Engine without the generator that tripped, communicate the new prices and wait for the generation and load to respond. In the time it takes the market participants to respond to the new prices the frequency decline may well have caused the system to fail. There are two primary design issues with ancillary services. The first is whether ancillary services are going to be co-optimized along with energy in order to obtain the least cost solution or whether they will be treated separately. The second is whether the Market

Administrator or another entity will be responsible for acquiring and/or deploying the individual ancillary services.

It should be clear from the previous four bullet points that there is no single best market design. There are successful markets in operation based on each of the choices available. What is important, however, is that once the choices about what kind of market is desired, i.e. the choices made with respect to scheduling, commitment, dispatch and ancillary services, the resulting rules are consistent with those choices.

We add one additional component to the four previous necessary operational elements of a successful electricity market:[39]

5. **Market monitoring** is the process that ensures that the integrity of the market is maintained. For a market to be successful the participants must be confident that rules are being obeyed and that there is no abuse of market power. This applies to Market Participants as well as to the Market Administrator.

Given the fundamental importance of the dispatch process to the operation and results of the market, we note that the primary source of information regarding dispatch is currently found in the National Electricity Grid Code and not the DEMR themselves. The result of this bifurcation of the rules pertaining to dispatch is incompleteness and inconsistency. In areas where a competitive market has been introduced it is common for dispatch rules to be contained in the market rules and for "grid codes" to contain the physical and technical standards by which the grid must be operated.

Market designs may differ in terms of who carries out the respective activity, e.g. generation units can self-commit or they can be instructed to be started by the Market Administrator, but the specific activity must be addressed by the rules. Specifically the market rules must address each of the following issues in order to define how the market will actually operate:

1. Scheduling:
    a. Unbalanced Schedules
        i. Voluntary financially binding Day Ahead Market.
    b. Balanced Schedules
        i. Penalties/incentives for adhering to the schedule.

2. Commitment:
    a. Self commitment.

[39] We don't include settlement or credit as explicit components because we assume those elements are contained within the appropriate individual categories, i.e. we assume that generators will be correctly paid when they are dispatched for providing either energy or ancillary services.

   b. Self commitment included in a centrally administered Security Constrained Unit Commitment process.

3. Dispatch:
   a. Real-time, bid based, Security Constrained Economic Dispatch.
   b. Pricing:
      i. Zonal or nodal.
      ii. LMP for generators at their node.
      iii. LMP for load at their node or by zones.
   c. Is the demand side, i.e. load, allowed to participate in the dispatch process?
   d. Hedging instruments, i.e. FTR's, for managing the price effects of constraints.

4. Ancillary Services
   a. Centrally procured and dispatched or decentralized?
   b. Co-optimized with energy or treated separately/additive to energy?

5. Market Monitoring
   a. Is the market monitoring unit internal or external to the market administration function?

The table in Appendix C presents a summary of the characteristics listed in 1-5 above for all the competitive markets currently operating and the DEMR for Ghana.

APPENDIX C: Competitive Wholesale Electricity Markets Comparison

	Scheduling		Commitment		Dispatch						A
	Pre-Dispatch Schedule	Financially Binding Day-Ahead Market	Self Commit	Centrally Administered SCUC[40]	Real-Time, Bid Based, SCED[41]	LMP	Settlement Prices Generation	Settlement Prices Load	Demand Participation	Financial Transmission Rights	C coo
North America:											
ISO-NE	Yes	Yes	Yes	Yes	Yes	Yes	Nodal LMP	Nodal/Multi Zone LMP	Yes	Yes	
NYISO	Yes	Yes	Yes	Yes	Yes	Yes	Nodal LMP	Nodal/Multi Zone LMP	Yes	Yes	
PJM	Yes	Yes	Yes	Yes	Yes	Yes	Nodal LMP	Nodal/Multi Zone LMP	Yes	Yes	
MISO	Yes	Yes	Yes	Yes	Yes	Yes	Nodal LMP	Nodal/Multi Zone LMP	Yes	Yes	
ERCOT	Yes	Yes	Yes	Yes	Yes	Yes	Nodal LMP	Nodal/Multi Zone LMP	Yes	Yes	
CAISO	Yes	Yes	Yes	Yes	Yes	Yes	Nodal LMP	Nodal/Multi Zone LMP	Yes	Yes	
Ontario	Yes	No	Yes	Yes	Yes[42]	No	Single *Ex Post* Unconstrained Price	Single *Ex Post* Unconstrained price	Yes	No	
Alberta	Yes	No	Yes	No	Yes	No	Single *Ex Post* Unconstrained Price	Single *Ex Post* Unconstrained Price	Yes	No	
Asia-Pacific:											
Philippines	Yes	No	Yes	No	Yes	Yes	Nodal LMP	Nodal/Multi Zone LMP	Yes	Yes	
Singapore	Yes	No	Yes	No	Yes	Yes	Nodal LMP	Single Zone	Yes	Yes	
Australia	Yes	No	Yes		Yes	Yes	Zonal LMP	Zonal LMP	Yes	Yes	
New Zealand	Yes	No	Yes	No	Yes	Yes	Nodal LMP	Nodal LMP	Yes	No	
Europe[43]:											
Ireland	Yes	No	Yes	Yes	Yes	Yes	Single *Ex Post* Unconstrained Price	Single *Ex Post* Unconstrained Price	Yes	No	
UK	Yes	No[44]	Yes		Yes		Zonal Imbalance Price	Zonal Imbalance Price	Yes	No	
Proposed:											
Ghana – DEMR	Yes	No	Yes	No	Yes	Yes	Nodal LMP	Single Zone	No	No	

40 Security Constrained Unit Commitment
41 Security Constrained Economic Dispatch
42 Unlike Singapore and the market proposed for Ghana, Ontario actually runs the dispatch algorithm twice – constrained and unconstrained. The results from the system while the results from the unconstrained model are used to develop the uniform energy price.
43 Nordpool relies on a separation of the financial and physical markets. The physical real time markets are run by the respective State-owned Transmission Syste Statnett SF., in Sweden it is Svnska Kraftnet, in Finland it is Fingrid and in Denmark it is Energinet.dk. This is a different structure than the proposed Ghanaian mar dispatch procedures for each of the TSOs.
44 The British Electricity Trading and Transmission Arrangements (BETTA) are based on balancing imbalances that occur around bilateral contracts. Although a sp clearing price, rather the design is based on "pay as bid", i.e. generators are paid their bid price and not a market clearing price.

APPENDIX D: Specific References to Sections in the DEMR and discussions in respect of Dispute Resolution Process, Mediation, Arbitration and Rule Change Process

Dispute Resolution Process

The dispute resolution provisions of Section 3.2.01 and 3.2.03 impose an obligation on the Market Participant to continue to pay monies in a timely manner and to follow the orders and directions of the ETU or MOP even when/if?? the dispute resolution process has been initiated. These provisions are consistent with industry best practices as they serve to allow the market to continue to function and the issue in dispute to be resolved through the proper process. Similar provisions regarding timely payments of monies owed and continued corporation by market participants are common throughout the tariffs of the US grid operators. DEMR Rule 3.2.05 preserves a party's right to seek injunctive relief from a court in Ghana, which likely would be invoked when the issue at dispute would result in irreparable harm to the disputing party.

DEMR Rules 3.2.06 through 3.2.13 set out the minimum requirements of each *market entity* to implement a Dispute Management System (DMS) detailing contact information and the party's procedures for responding to requests for information. The parties to a dispute are expected to try to resolve the dispute using their DMSs. These requirements are similar to that of information dispute resolution; however, the required development of a DSM by each *market entity* creates the possibility of conflicting DMS provisions and an inability to work within the DMS framework to resolve disputes. This potential for conflicting DMS provisions may be mitigated based upon the notes of the MOP as contemplated in DEMR Rule 3.2.06 (c).

11.1 MOP Review of Dispute Resolution Procedures

Pursuant to DEMR Rule 3.2.83 the MOP shall conduct a review of the dispute resolution procedures at least once every three years. Given the high volume of disputes that are generally experienced upon the start of a new market, it is recommended that an obligation be placed on the MOP to review the dispute resolution procedures once per year for the first three years of the market and then at least once every three years. The recommendation for this more frequent review period is intended to identify and address any issues with the dispute resolution procedures that arise upon initial implementation.

Mediation

The mediation process described in DEMR Rules 3.2.14 through 3.2.33 appears to continue to focus on the resolution of the dispute by the parties until such resolution is not possible and then the engagement of the MOP. There a very few conditions placed upon the MOP when selecting a mediator to a dispute. The DEMR could be improved by listing more specific qualifications that must be met by the person selected as the mediator. For example, the MOP could maintain a list of qualified mediators who are educated in mediations, have substantial technical and subject matter expertise and who have provided a list of potential conflicts.

Also with regard to the mediation provisions in the DEMR, Rule 3.2.31 states:

> **Rule 3.2.31** Failure to comply with a settlement agreement is a breach of the *market rules*.

This statement appears to be misplaced in the DEMR as a stand-alone rule. Because a settlement agreement is a negotiated agreement between the parties the claim that failure to comply with a settlement agreement is a breach of the *market rules* is somewhat concerning. To the extent that DEMR Rule 3.2.31 is in reference to the failure to comply with the payment obligations of a party stated in Rule 3.2.30, Rule 2.3.31 should be incorporated into the previous rule.

> **Rule 3.2.30** Where as a result of mediation, the parties to a dispute enter into a settlement agreement in writing where the parties agree that monies are due and payable by one party to another under the *market rules*, such agreement shall be considered to create an obligation under the *market rules* to pay the amount agreed and such amount may, without prejudice to any other remedy available at law, be recovered accordingly.

If the statement in DEMR Rule 3.2.31 is intended to stand-alone as it is written it brings into question whether any breach of a settlement agreement in addition to the identified obligation to pay under the Rule 2.3.30. It is recommended that clarification be sought as to whether Rule 3.2.31 applies to any form of non-compliance with a settlement agreement as it would generally be the case that the parties would seek a remedy at law for breach of contract rather than non-compliance with the Market Rules.

Arbitration

The DEMR provide for binding arbitration through the use of a three person arbitration tribunal. Of specific importance is the statement in Rule 3.2.66 that an agreement reached or determination of the arbitration tribunal is binding and not subject to appeal:

> **Rule 3.2.66** An agreement reached in respect of the dispute before the arbitration tribunal or a determination of the *arbitration tribunal* is binding and is not subject to appeal.

The statement "not subject to appeal" suggests that a determination of the arbitration tribunal is final and raises the question as to whether it could be appealed to a court of competent jurisdiction given the statement in Rule 3.2.67:

> **Rule 3.2.67** A determination of an *arbitration tribunal* may with the leave of a court of competent jurisdiction be enforced as if it were a judgment or order of the court.

Rule 3.2.68 states that failure to comply with a determination of the arbitration tribunal shall be deemed a breach of the market rules:

> **Rule 3.2.68** Failure to comply with a determination of the *arbitration tribunal* shall be deemed a breach of the *market rules*.

As discussed above with regard to settlement agreements, the statement that the failure to comply with a determination of the arbitration tribunal shall be deemed a breach of the Market Rules appears to be misplaced in that enforcement of the provisions of an arbitration tribunal determination would be sought through an action at law for breach of the determination rather than a breach of the Market Rules.

Rule Change Process

The process by which the rules can be changed is given in Section 3.4:

> **SECTION 3.4 - MODIFICATION OF THE RULES**
>
> **Introduction**
>
> **Rule 3.4.01** The *market rules* may be *modified* by the *MOP* under *Rule 3.4.02*.
>
> **Rule 3.4.02** The MOP may modify the market rules by a resolution passed by at least two-thirds of the members in office at the time, excluding any who abstain voluntarily or who are required by the constituent document to abstain.
>
> **Requests to review or modify market rules**
>
> **Rule 3.4.03** The MOP, the ETU, the Energy Commission, a market participant or any other interested person (each of whom is referred to in the market rules as a proposer), who considers that a modification or review of the market rules may be necessary or desirable, may submit a modification proposal.
>
> **Rule 3.4.04** A *modification proposal* by a *proposer* shall be made in writing, stating the reasons for the *modification proposal* and be sent to the *MOP* at the address that is *publish*ed by the *ETU* for that purpose.
>
> **Rule 3.3.05** Where the *MOP* determines on its own initiative that a *modification* or review of the *market rules* may be necessary or desirable, it

shall notify the *ETU* and the *EC* of its intention to consider such *modification* or review, giving reasons for its determination.

Rule 3.4.06 Where the *ETU* determines on its own initiative, or at the request of any person, that a *modification* or review of the *market rules* may be necessary or desirable, it shall submit a *modification proposal* in accordance with *Rule 3.4.03 and Rule 3.4.04*.

Duties of *MOP* when considering a modification proposal

Rule 3.4.07 Before the *MOP* considers any *modification proposal*, the *ETU* shall *publish* the details of the *modification proposal*, with comments from the *MOP* and invite all interested persons to make written submissions on the *modification proposal* to the *MOP* within a reasonable period specified in the invitation.

Rule 3.4.08 All submissions must be made within the period specified in the relevant invitation *published* by the *ETU*.

Rule 3.4.09 A person who makes such a submission may at the same time indicate that a meeting in connection with the *modification proposal* is necessary or desirable, giving his reasons therefor.

Rule 3.4.10 The *MOP* may invite interested persons to make additional submissions in writing within the period specified by the *MOP* in respect of a *modification proposal*.

Rule 3.4.11 All submissions that are received by the *MOP* within the time specified for making submissions shall be considered by the *panel* which may decide to hold one or more public meetings if it thinks that it is necessary or desirable to do so.

Rule 3.4.12 The *MOP* shall advise the *ETU* and the *EC* of the date, time and place scheduled for any public meeting and the ETU shall *publish* this information at least seven days before the date of the meeting.

Rule 3.4.13 An interested person may attend the meeting.

Consideration of modification proposal by *MOP*

Rule 3.4.14 As soon as reasonably practicable after all meetings and consultations have been completed, and after any further meetings or consultations that the *MOP* considers appropriate, the *MOP* shall consider the *modification proposal*.

Rule 3.4.15 After it has considered a *modification proposal*, the *MOP* shall send a written report to the *ETU* and the *EC* which shall contain the following:

(a) the recommendations of the *MOP* together with reasons for the recommendations :

(i) that the *modification proposal* does not warrant consideration;
(ii) that the *modification proposal* only requires clarification or interpretation;
(iii) that the *market rules* not be *modified*; or
(iv) that the *market rules* be *modified*;

(b) the text of any *modification* proposed by the *market oversight panel*, and a summary of any objections the *panel* received on it or brought to its attention;

(c) a record of how each member of the *MOP* voted; and

(d) a summary of any *panel* member's objections to the *panel*'s recommendation.

ETU to publish *MOP*'s report

Rule 3.4.16 The *ETU* shall *publish* each recommendations report unless the *market oversight panel* has decided that publication is inappropriate in a particular case.

Rule 3.4.17 Where the *market oversight panel*'s report recommends that the *market rules* should be *modified* but that its report should not be *publish*ed, the *ETU* shall, in any case, *publish* the text of the proposed *modification*.

Rule 3.4.18 If the *market oversight panel*'s text of the proposed *modification* differs materially from the text that was originally proposed, the *proposer* of the original text may object to the *panel*'s proposed text in writing, stating the reasons for the objection, to the *Energy Commission* within five *business days* of the date that the *ETU publish*es the text of the proposed *modification*.

Energy Commission to consider *MOP*'s report

Rule 3.4.19 Within sixty days after the *EC* has received a report, the *EC* shall consider the report and any objections in respect of the matter.

Rule 3.4.20 Where the *market oversight panel* has made a recommendation that the *modification proposal* does not warrant consideration or that the *modification proposal* only requires clarification or interpretation, the *EC* may require the *market oversight panel* to reconsider the *modification proposal*.

Rule 3.4.21 Where the *market oversight panel* recommends that the *market rules* should be *modified*, the *EC* may:

(a) decline to adopt the recommendation subject to *Rule 3.4.22* and *Rule 3.4.23*; a

(b) adopt the recommendation, either in the form proposed by the *market oversight panel* or as amended by the *EC* as it considers appropriate

Energy Commission may decline to adopt a modification

Rule 3.4.22 The *EC* may only decline to adopt a recommendation of the *market oversight panel* to *modify* the *market rules* if the *EC* determines that the *modification* would:

(a) materially threaten the ability of the ETU to direct the operation or maintain the *reliability* of the NITS and the ETU consents to this determination;

(b) materially affect the ability of the *ETU* to operate the *wholesale electricity markets* in an efficient manner;

(c) give a *market participant* or a class of *market participants* an undue preference in the *wholesale electricity market*;

(d) materially increase the opportunity for *market participants* or any class of *market participant* to engage in inappropriate or anomalous market conduct, including the misuse or possible misuse of market power, gaming or collusion;

(e) impose, without due justification, significant extra costs on *market participant*s or any class of *market participant*s; or

(f) impose, without due justification, significant extra costs on the *ETU*.

Rule 3.4.23 Where the *EC* declines to adopt a *modification* to the *market rules*, the *EC* shall:

(a) *publish* its decision with reasons; and

(b) if the decision relates to a provision of Chapter 4, provide a copy of the decision to the *ETU*.

Energy Commission may decide to adopt a modification

Rule 3.4.24 If the *market oversight panel* recommends that the *market rules* should not be *modified*, the *EC* shall not *modify* the *market rules* without first referring the *modification proposal* back to the *market oversight panel* for reconsideration.

Rule 3.4.25 If the *market oversight panel* has reconsidered a *modification proposal*, and still recommends that the *market rules* should not be *modified*, the *EC* shall not *modify* the *market rules* unless the *EC* determines that the *modification* would:

(a) materially enhance the ability of the *ETU* to direct the operation or maintain the *reliability* of the *NITS*;

(b) materially enhance the ability of the *ETU* to operate the *wholesale electricity market* in an efficient manner;

(c) eliminate or materially reduce an undue preference that a *market participant* or any class of *market participant*s may have in the *wholesale electricity market*;

(d) eliminate or materially reduce the opportunity for *market participant*s or any class of *market participants* to engage in inappropriate or anomalous market conduct, including the misuse or possible misuse of market power, gaming and collusion;

(e) eliminate or materially reduce the costs of *market participant*s or any class of *market participants*; or

(f) eliminate or materially reduce the costs of the *ETU*, and that the benefit outweighs the objections of the *market oversight panel* to the *modification*.

Rule 3.4.26 Where the *EC* adopts a *modification* to the *market rules*, the *ETU* shall *publish* the decision, together with details of the *modification*.

Energy Commission may refer a modification proposal back to *MOP*

Rule 3.4.27 The *EC* shall give and publish the reasons for referring any *modification proposal* back to the *market oversight panel.*

Rule 3.4.28 If the *EC* has referred any *modification proposal* back to the *market oversight panel* for reconsideration, the *panel* shall reconsider it within 30 days and may consult any person, and conduct any meeting, that it thinks is appropriate in the circumstances.

Rule 3.4.29 The *market oversight panel* shall in reconsidering the *modification proposal,* follow the same procedures applicable to a new modification proposal with such modifications as the context may require.

Energy Commission approval and effectiveness of modified rules

Rule 3.4.30 If a *modification* to the *market rules* is filed with the *Energy Commission* for approval, the *Energy Commission* shall give that approval , unless the *Energy Commission* is satisfied that the *modification*:

(a) unjustly discriminates in favour of or against a *market participant* or a class of *market participants*; or

(b) is inconsistent with the functions and duties of the *Energy Commission.*

Rule 3.4.31 The *Energy Commission* shall notify the *MOP* and the *ETU* of its decision concerning a *modification* to the *market rules* within 15 *business days* of receiving the *modification* request, unless that period has been extended, and the *ETU* shall promptly *publish* the decision in respect of the approved *modification*.

Rule 3.4.32 *Modification*s approved by the *Energy Commission* shall come into force on:

(a) the first *business day* after the *ETU publish*es the notice of the *Energy Commission*'s decision; or

(b) any later date that the *ETU* specifies when it *publish*es the notice of the *Energy Commission*'s decision.

As noted and discussed elsewhere in this report the "real" market rules are contained in the Grid Code and for purposes of comparison we provide the process by which the Code can be changed:

> ***Revision of Grid Code***
>
> ***Art 5.24*** *– Proposals for the revision of any provision of the Grid Code may be made by any Grid Participant or the ETU, the "Proposer"*
>
> ***Art 5.25*** *– All proposals for Grid Code revisions shall be in writing and shall be sent to the Energy Commission with a copy to the ETU.*
>
> ***Art 5.26*** *– The Energy Commission shall receive, register and acknowledge all submissions and pass on the proposals to the Secretariat of the ETC located at the Energy Commission.*
>
> ***Art 5.27*** *– The Secretariat of the ETC shall notify all Grid Participants and the ETU of all such proposals and make copies accessible to them either over the internet or through other appropriate means.*
>
> ***Art 5.28*** *– The ETU shall within three months of its receipt of a revision proposal, provide the ETC and the "Proposer" with its views, comments and advice on each proposal.*

> ***Art 5.29*** *– The ETC shall consider each revision proposal at the next regular meeting and make recommendations which shall be forwarded to the Energy Commission.*
>
> ***Art 5.30*** *– The Energy Commission shall consider the submissions of the "Proposer", the ETU and ETC and advise all the parties of its decision with full and written justifications.*

We make the observation that the rule change process outlined in the Grid Code is less specific, less transparent, and it is left to the EC to ensure consistency across the two set of rules.

The rule change process described in Section 3.4 is an acceptable methodology. We assume that the Market Oversight Panel, in evaluating a rule change proposal, may require technical assistance and this should be part of their budget.

APPENDIX E: Specific References to Sections in the DEMR in respect of Scheduling, Commitment and Dispatch

Scheduling

Scheduling is the process of assuring enough generators are connected to the system, at appropriate locations to meet the load forecast, taking into consideration transmission limitations, transmission congestion, and meeting all the expected needs of generation based on Ancillary Services so that the system will reliably meet the load.

The DEMR Scheduling Rules are contained in Sections 4.3 and 4.4.

Section 4.3 of the DEMR

SECTION 4. 3 - ENERGY, RESERVE AND REGULATION OFFERS

Obligation to Have Offers

Rule 4.3.01 Each *generation registered facility* shall at all times have a valid *standing offer* for *energy* for each *dispatch period* of each day of the week.

Rule 4.3.02 If a *generation registered facility* is *registered* to provide:

(a) *reserve* of a *reserve class*, it shall at all times have a valid *standing offer* for *reserve* of that *reserve class*; and
(b) *regulation*, it shall at all times have a valid *standing offer* for *regulation*, for each *dispatch period* of each day of the week.

Rule 4.3.03 If a *load registered facility* is *registered* to provide *reserve* of a *reserve class*, it shall at all times have a valid *standing offer* for *reserve* of that *reserve class* for each *dispatch period* of each day of the week.

Rule 4.3.04 A *dispatch coordinator* may revise a *standing offer* at any time subject to the gate closure requirements.

Rule 4.3.05 For any *dispatch period* in the current *market outlook horizon*, if the quantity currently *offered* in a valid *offer* for a generation *registered facility*, exceeds the relevant quantity that its *dispatch coordinator* reasonably expects to be available from the *registered facility* by more than:

(a) **5 MW**; or
(b) X percent of the quantity currently *offered {X to be determined with GridCo}*,

Which ever is greater, then that *dispatch coordinator* shall immediately submit an *offer variation* for that *registered facility* to the *ETU*.

Rule 4.3.06 For each *dispatch period* that a generation *registered facility* is not *synchronised* and until the earliest *dispatch period* in which it would be possible for that *registered facility* to be *synchronised*, its *dispatch coordinator* shall:

(a) Submit *offer variations* where there are existing *offer variations*; or
(b) submit revised *standing offers* where there are no *offer variations,*

so that all the *offered* quantities are zero.

Rule 4.3.07 The *dispatch coordinator* of a *registered facility* shall*,* to the extent necessary for consistency with any *standing capability data* that is revised and approved, submit revised *standing offers* and *offer variations* that apply from the time that revised *standing capability data* takes effect.

Form of Energy Offers

Rule 4.3.08 Each energy offer is an offer to provide energy to the relevant real-time market by a generation registered facility at its market network node in a dispatch period.

Rule 4.3.09 Each *energy offer* shall state:

(a) the identity of the *generation registered facility* that the *energy offer* is for;
(b) if it is a *standing offer* or an *offer variation*;
(c) the *dispatch period* that the *energy offer* is for;
(d) the maximum combined capacity of the *generation registered facility* for *energy*, *reserve* and *regulation* for the *dispatch period*; and
(e) the *energy* ramp-up rate and the *energy* ramp-down rate, which respectively imply the allowable increase and decrease in the output of the *generation registered facility* during the *dispatch period*.

Rule 4.3.10 The *generation registered facility* that the *energy offer* is for

must be *registered* to provide *energy*.

Rule 4.3.11 The price of an *energy offer* shall:

(a) be the plant *short run marginal cost* as agreed with and approved by the ETU; and
(b) be expressed in GH¢/MWh to two decimal places.

Rule 4.3.12 The quantity of an *energy offer* shall be expressed in MW to one decimal place and shall not be less than 0.0 MW.

Rule 4.3.13 If the quantity of an *energy offer* is 0.0 MW, the corresponding price shall be GH¢0.00/MWh.

Rule 4.3.14 The total of the quantities of an *energy offer* for a *dispatch period* shall not exceed:

(a) the maximum *generation capacity*, indicated in the relevant *generation registered facility*'s *standing capability data* which shall comply with of APPENDIX 4D for that *dispatch period*;
(b) the maximum quantity of *energy* that can be supplied in that *dispatch period* by that *generation registered facility*, as reasonably estimated by its *dispatch coordinator*; or
(c) the maximum combined capacity of that *generation registered facility* for *energy*, *reserve* and *regulation* stated in the *energy offer*.

Rule 4.3.15 The maximum combined capacity of the *generation registered facility* for *energy*, *reserve* and *regulation* stated in an *energy offer* under *Rule 4.3.14* shall be expressed in MW to one decimal place and not be less than 0.0 MW.

Rule 4.3.16 The *energy* ramp-up rate and the *energy* ramp-down rate stated in an *energy offer* shall each:

(a) be expressed in MW/minute to one decimal place;
(b) be less than 0.0 MW/minute; and
(c) not exceed respectively the maximum ramp-up rate and maximum ramp-down rate indicated in the relevant *generation registered facility*'s *standing capability data*.

Form of Reserve Offers

Rule 4.3.17 Each *reserve offer*:

(a) is an *offer* to provide *reserve* to the relevant *real-time market* by a *generation registered facility* or a *load registered facility* in a *dispatch period*;
(b) applies only to one *reserve class*; and

(c) constitutes an *offer* to provide *reserve* within the *reserve provider group* to which the *generation registered facility* or the *load registered facility* (as the case may be) has been assigned by the *MA* for that *reserve class*.

Rule 4.3.18 Each *reserve offer* shall state:

(a) the identity of the *generation registered facility* or *load registered facility* that the *reserve offer* is for;
(b) if it is a *standing offer* or an *offer variation*;
(c) the *reserve class* that the *reserve offer* relates to;
(d) the *dispatch period* that the *reserve offer* is for; and
(e) if the *reserve offer* is for a *generation registered facility*, or a *reserve* proportion which constrains the maximum *reserve* that may be scheduled from that *generation registered facility* to a specified ratio of its *energy* scheduled.

Rule 4.3.19 The *generation registered facility* or *load registered facility* must be *registered* to provide *reserve* for the *reserve class* that its *reserve offer* is for.

Rule 4.3.20 The price of a *reserve offer* shall:

(a) be the *short run marginal cost* as agreed with and approved by the ETU
(b) be expressed in GH¢/MWh to two decimal places;
(c) not exceed the upper price limit for the applicable *reserve class*; and
(d) not be less than GH¢0.00/MWh.

Rule 4.3.21 The quantity of a *reserve offer* shall be expressed in MW to one decimal place and must not be less than 0.0 MW.

Rule 4.3.22 If the quantity of a *reserve offer* is 0.0 MW, the corresponding price shall be GH¢0.00/MWh.

Rule 4.3.23 The total of the quantities in all the *reserve offers* of a *dispatch period* shall not exceed:

(a) the maximum *reserve* capacity for that *reserve class*, indicated in the relevant *generation registered facility* or *load registered facility*'s *standing capability data* for that *dispatch period*; or
(b) the maximum quantity of *reserve* that can be supplied for that *reserve class* in that *dispatch period* by that *generation*

registered facility or *load registered facility*, as reasonably estimated by its *dispatch coordinator*.

Rule 4.3.24 The *dispatch coordinator* shall state in a *reserve offer* the *reserve* proportion that minimises the likelihood of the *generation registered facility* being scheduled to provide more *reserve* than it can reliably provide at any given level of scheduled *energy*.

Rule 4.3.25 The *reserve* proportion stated in a *reserve offer* shall:

(a) not be less than zero; and

(b) not exceed the *reserve* proportion indicated in the relevant *generation registered facility*'s *standing capability data*.

Form of Regulation Offers

Rule 4.3.26 Each *regulation offer* is an *offer* to provide *regulation* to the relevant *real-time market* by a *generation registered facility* in a *dispatch period*.

Rule 4.3.27 The *ETU* shall use a *regulation offer* of a *generation registered facility* to produce *market schedules* only if it is *synchronised* and its forecast generation level at the beginning of that *dispatch period* indicates that it is able to provide *regulation*.

Rule 4.3.28 Each *regulation offer* shall state:

(a) the identity of the *generation registered facility* that the *regulation offer* is for;
(b) if it is a *standing offer* or an *offer variation*; and
(c) the *dispatch period* that the *regulation offer* is for.

Rule 4.3.29 The *generation registered facility* that the *regulation offer* is for must be *registered* to provide *regulation*.

Rule 4.3.30 The price of a *regulation offer* shall:

(a) the *short run marginal cost* as agreed with and approved by the ETU
(b) be expressed in GH¢/MWh to two decimal places;
(c) not exceed the upper price limit; and
(d) not be less than GH¢0.00/MWh.

Rule 4.3.31 The quantity of a *regulation offer* shall be expressed in MW to one decimal place and shall not be less than 0.0 MW.

Rule 4.3.32 If the quantity of a *regulation offer* is 0.0 MW, the corresponding price shall be GH¢0.00/MWh.

Rule 4.3.33 The total of the quantities of the *regulation offers* shall represent both the maximum increase and the maximum decrease in *energy* output that the relevant *generation registered facility* can achieve for the purpose of providing *regulation*.

Rule 4.3.34 The total of the quantities of the *regulation offers* of a *dispatch period* shall not exceed:

(a) the maximum *regulation* capacity, indicated in that *generation registered facility*'s *standing capability data* for that *dispatch period*; or
(b) the maximum quantity of *regulation* that can be supplied in that *dispatch period* by that *generation registered facility*, as reasonably estimated by its *dispatch coordinator*.

Communication of Offers

Rule 4.3.35 Each *offer* shall:

(a) be submitted using the forms, procedures and data formats prescribed in the applicable *market manual*; and
(b) comply with the requirements in *Rule 4.3.08 to Rule 4.3.16,Rule 4.3.17 to Rule 4.3.25 or Rule 4.3.26 to Rule 4.3.34*;
(c) comply with the requirements of Data Submission process in APPENDIX 4; and
(d) be submitted to the *ETU* by the applicable *dispatch coordinator* via the *electronic communications system* or in accordance with *Rule 4.3.47(b)*.

Receipt of Offers

Rule 4.3.36 When the *ETU* receives any *offer*, it shall:

(a) stamp the *offer* with the time that it was received;
(b) within five minutes, confirm receipt of the *offer*; and

(c) within five minutes, validate the *offer* in accordance with *Rule 4.3.40(a)*and release information indicating that the *offer* has been:
    (i) accepted as valid; or
    (ii) rejected, with reasons for the rejection.

Rule 4.3.37 If a *dispatch coordinator* does not receive confirmation of receipt or information of the acceptance or rejection of an *offer* from the *ETU* in accordance with *Rule 4.3.40*, it shall immediately inform the *ETU*. If the problem lies with the *ETU*'s communications systems, the *ETU* shall take steps to rectify the problem as soon as possible.

Rule 4.3.38 For a given *registered facility*, if any revised *standing offer* or *offer variation*:

(a) is not communicated to the *ETU*, or
(b) is rejected by the *ETU*,

the last accepted valid *standing offer* for the relevant *dispatch period* shall apply.

Rule 4.3.39 However, if that *registered facility* has a last accepted valid *offer variation* for that *dispatch period*, that *offer variation* shall apply instead.

Validation of Offers

Rule 4.3.40 The *ETU* shall determine if each *offer*:

(a) complies with the *market manual*;
(b) complies with the requirements in *Rule 4.3.08 to Rule 4.3.16 or Rule 4.3.17 to Rule 4.3.25 or Rule 4.3.26 to Rule 4.3.34*; and
(c) complies with requirements in Section D7 of Appendix 4D.

Rule 4.3.41 If an *offer* satisfies both conditions, the *ETU* shall accept the *offer* as valid and if not, the *ETU* shall reject the *offer*.

How Offers are Used

Rule 4.3.42 All *offers* shall, if accepted as valid by the *ETU*, be stored by the *ETU*.

Rule 4.3.43 Subject to *Rule 4.3.44* and *Rule 4.3.45*, the *ETU* shall use the last accepted valid *standing offer*, except that, if there is a last accepted valid *offer variation*, the *ETU* shall use that *offer variation* instead, to produce *market schedules* for the applicable *dispatch period*.

Rule 4.3.44 If an *offer* for a *dispatch period* was accepted as valid less than five minutes before the production of a *market schedule* containing that *dispatch period*, that *offer* is not guaranteed to be used by the *ETU* in the production of that *market schedule*.

Rule 4.3.45 If an *offer variation* for a *dispatch period* was submitted after that *dispatch period* had begun, the *ETU* shall not use that *offer variation* in the production of any *market schedule* containing that *dispatch period*.

Electronic Communication System for Offers

Rule 4.3.46 The *ETU* shall have an *electronic communications system* that allows for:

(a) the submission of *standing offers* and *offer variations* by *dispatch coordinators*;

(b) the communication by the *ETU* to each *dispatch coordinator* of the acceptance or rejection of *standing offers* and *offer variations*;

(c) the issuance by the *ETU* of *market outlook scenarios*, *pre-dispatch schedule scenarios, short-term schedules* and *real-time dispatch schedules* and the associated pricing schedules, on a timely basis and in a manner consistent with these *market rules*.

Rule 4.3.47 The *ETU* shall *publish* in the applicable *market manual*:

(a) the protocols and procedures for the use of the *electronic communications system*; and
(b) the method by which exchanges of the data referred to in *Rule 4.3.46*shall be communicated in the event of a failure of the *electronic communications system*.

4.1.1 Comment on Section 4.3 of the DEMR

The DEMR specify that generators submit single part offers, i.e. GH¢/MWh to two decimal places that represent the “short run marginal cost” as defined below:

Rule 4.1.17 The price used in the dispatch of a generation registered facility shall reflect the *short run marginal cost* (SRMC) of the facility.

Rule 4.1.18 The *short run marginal cost* is the sum of the Variable Operating and Maintenance Costs and the Fuel Costs associated with the operation of the generating facility.

Rule 4.1.19 The equation for calculating the *SRMC for a generation registered facility* shall be as follows:

$$SRMC = H_R \times F_C + F_{O\&M}$$

where: H_R is Heat Rate of generating facility in MMBTU per kWh
F_C is the cost of fuel in US$ per MMBTU
$F_{O\&M}$ is the fixed operation and maintenance cost per kWh

From these two rules it is not apparent how or even if a generator will be allowed to recover (1) the costs associated with start up, minimum run and shut down which are fixed and not variable costs and (2) the costs associated with the capital investment.

Rule 4.1.17 says that the price used in dispatch is the SRMC, and then Rules 4.1.18 and 4.1.19 provide opposing definitions of marginal cost. Rule 4.1.18 is the textbook (and correct) definition of marginal costs, i.e. that it is the change in variable costs. In comparison Rule 4.1.19 includes a fixed operation component which means it is no longer marginal cost. Thus these two rules are inconsistent. If in fact, the SRMC is allowed to include the fixed elements in Rule 4.1.19, then it is no longer the SRMC.

Section 4.3 describes a market based on single part offers. In markets based on this design philosophy, generators must be allowed to include the return to capital along with the variable costs associated with operation and maintenance expenditures. If generators are only allowed to recover their variable costs, then they will lose money regardless of the level of their production. Therefore, we can assume that Rule 4.1.19 takes precedence over the language in Rule 4.1.18, which should be removed from the DEMR. The rules should also make clear that “fixed operation and maintenance cost” is meant to include the return to capital. However, the return to capital is not “fixed”, it varies with the value of the asset as well as the cost of capital and the “SRMC” for a generation registered facility should be allowed to vary accordingly.

In addition, the offers from generators must be allowed to include the costs associated with start-up, shut-down and minimum run. The alternative to single part offers are either two or three part offers. With two part offers, the generator offer consists of the MC of production and the start-up and no load costs. A three-part offer would add the load necessary for minimum run operation. There is nothing inherently better or worse about a market based on single, two or three-part offering. The choice does however, have a significant effect on the structure of other design elements. For example, where the market design allows for the dispatcher to start generation units for reliability purposes the objective function for the commitment decision is to minimize the cost of acquiring the capacity – a task made easier when the design is based on two or three-part offers. The task of monitoring offers with regard to monopoly behaviour is more difficult under a single part regime because the generators must be allowed to include the return to capital which may be different for every generator connected to the system.

The DEMR do not specify how many tranches a generator can offer. Normally we would expect that regardless of the technology, the cost of generation and hence the offer curve for a generator will be monotonically non-decreasing and this should be reflected in the rules governing offering behaviour as well. Therefore, we would recommend that a generator's offer curve consist of up to ten tranches of price/quantity pairs that must be monotonically non-decreasing.

The Rules and the Appendices are silent on how the ETU will transform the individual offer curves into an aggregate supply curve for purpose of running the Market Clearing Engine.

4.1 Section 4.4 of the DEMR

Section 4.4 of the DEMR provides the rules regarding how the Dispatcher/Market Operator will prepare the dispatch schedule in preparation for real time.

SECTION 4.4 - PREPARATION OF MARKET OUTLOOK HORIZON

Market Outlook Horizon Data

Rule 4.4.01 The *ETU* shall, on each *dispatch day* and in accordance with the *market operations timetable*:

(a) conduct such analysis as may be necessary to determine the appropriate parameters to be used as inputs to the *market clearing engine* for each *dispatch period* in the current *market outlook horizon*;

(b) determine or update, as the case may be, the *dispatch related data* referred to in Appendix 4E for each *dispatch period* in the *market outlook horizon*; and

(c) communicate the *dispatch related data* referred to in *Rule 4.4.01*(b) to the *MA and other market participants*.

Terminology and Purpose

Rule 4.4.02 The *market outlook horizon* is, at any given point in time, the period running continuously from that point in time to the end of the seventh *dispatch day* thereafter.

Rule 4.4.03 The *pre-dispatch horizon* shall:

(a) at any given time before 12:00 hours on a given *dispatch day*, cover all *dispatch periods* commencing at the end of the current *dispatch period* and ending following the end of the last *dispatch period* of the current *dispatch day*; and

(b) at any given time at or after 12:00 hours on a given *dispatch day*, cover all *dispatch periods* commencing at the end of the current *dispatch period* and ending following the end of the last *dispatch period* of the *dispatch day* following the current *dispatch day*.

Rule 4.4.04 The *short-term horizon* shall, at any given point in time, cover twelve consecutive *dispatch periods* commencing immediately after the end of the current *dispatch period.*

Rule 4.4.05 The *ETU* shall determine *market outlook scenarios, pre-dispatch schedule scenarios* and *short-term schedules* in order to provide itself and the *market participants* with advance information and projections necessary to plan the physical operation of the *ETU controlled system* and *registered facilities* and to manage *load* over the *market outlook horizon*.

Load Forecasting

Rule 4.4.06 The *ETU* shall prepare and update, on the basis of the data received from the market participants and in accordance with *Rule 4.4.01(c)*the following three *market reference node load forecasts* covering the remainder of the current *market outlook horizon*:

(a) a normal *load* forecast, being based on the expected system *load* forecast provided by the market participants

(b) a low forecast, being *base*d on the expected system *load* forecast referred to in *Rule 4.4.06(a)*less the load sensitivity factor; and

(c) a high forecast, being based on the expected system *load* forecast referred to in *Rule 4.4.06(a*) plus the load sensitivity factor; where the load sensitivity factor shall be a fixed MW quantity determined and *published* by the *ETU* from time to time.

Rule 4.4.07 The *market reference node load forecasts* described in *Rule 4.4.06*, comprising a forecast of *load* for each *dispatch network node* for the relevant *dispatch period,* shall be prepared by applying the *load* participation factors to the forecast of *non-dispatchable load* provided by the *MA.*

Rule 4.4.08 The *load participation factor for a giv*en *dispatch period* shall be determined by the *ETU* usi*ng load* dispos*ition for similar day*s and similar *dispatch periods* based on his*tor*ical *metering data,* as the *ETU* dee*ms appropriate.*

Rule 4.4.09 The *load* participation fac*tor*s for a*ll dispatch network nodes* for a given *dispatch period shall sum to on*e.

Rule 4.4.10 The methodology, including revision*s t*hereof, for determining the *load p*articipation factors shall be *published* by the *ETU.*

Rule 4.4.11 In *the event that* the *ETU f*orecasts a shortfall of *energy* for any *dispatch period* within the first two hours of the *market outlook horizon*, the *ETU* shall immediately adjust the *market reference node load forecasts* described in *Rule 4.4.06* for the corresponding *dispatch periods* to reflect the shortfall quantities and locations specified by the *ETU*.

Rule 4.4.12 Notwithstanding Section 1.12, no *market participant* shall be entitled to compensation from the *ETU* for any financial loss sustained by the *market participant* due to the *market participant* having been *dispatched* on the basis of *load* as forecasted pursuant to the provisions on *load forecasting* under this section rather than on the basis of actual *load.*

Determining Market Outlook Scenario

Rule 4.4.13 The *ETU* shall determine three *market outlook scenarios* corresponding to the *reference node load forecasts* described in *Rule 4.4.06*, adjusted where applicable under *Rule 4.4.11.*

Rule 4.4.14 Each *market outlook scenario* shall include all *dispatch periods* between the end of the *pre-dispatch horizon* current at the time when the *market outlook scenario* is due to be released and the end of the *market outlook horizon* current at the time when the *market outlook scenario* is due to be released in accordance with *Rule 4.4.28.*

Determining Pre-Dispatch Schedule Scenario

Rule 4.4.15 The *ETU* shall determine three *pre-dispatch schedule scenarios* corresponding to the *market reference node load forecasts*, adjusted where applicable under *Rule 4.4.11*.

Rule 4.4.16 Each *pre-dispatch schedule scenario* shall include all *dispatch periods* in the *pre-dispatch horizon* current at the time when the *pre-dispatch schedule scenario* is due to be released in accordance with *Rule 4.4.29*.

Rule 4.4.17 The pre-dispatch schedule will always cover

(a) at least 12 hours and not more than 36 hours of time.
(b) before noon the period up to the end of the current dispatch day; and
(c) after noon the period up to the end of the next dispatch day.

Rule 4.4.18 The market outlook scenario will cover the remaining 6 days to the end of the market outlook horizon.

Determining Short-Term Schedule

Rule 4.4.19 The *ETU* shall determine a *short-term schedule* corresponding to the *nodal load forecast* described in *Rule 4.4.06(a).*

Rule 4.4.20 The *short-term schedule* shall always cover 12 consecutive dispatch periods and shall include all *dispatch periods* in the *short-term horizon* current at the time when the *short-term schedule* is due to be released.

Information Used in each Scenario or Schedule

Rule 4.4.21 The *ETU* shall use the following information to determine and revise each of the scenarios referred to in *Rule 4.4.13 to Rule 4.4.20*using the most current valid information:

(a) *offers* for the relevant *dispatch period h*eld by the *ETU*
(b) *standing capability data a*s applicable to each *dispatch period r*epresented within the *short-term horizon, pre-dispatch horizon a*nd the *market outlook horizon,* as the case may be, held by the *ETU;*
(c) the applicable *market reference node load forecasts* the *dispatch related data* received from the market participants;
(d) the initial loading of each *generation facility,* determined:
  (i) in the case of each *market outlook scenario*, on the basis of the end of the last *dispatch period* represented in the most recently *published pre-dispatch schedule* which was determined using the same *market reference node load forecast* and that contains the applicable *dispatch period*; and
  (ii) in the case of each *pre-dispatch schedule scenario*, on the basis of the later of the *real-time dispatch schedule* for the period after the current *dispatch period* (if available) and the *real-time dispatch schedule* for the current *dispatch period*;

(e) the *import limit* and *export limit*;
(f) the applicable price limits; and
(g) such other parameters or data as may be required to enable the *market clearing engine* to determine the required outputs.

Solving each Scenario Schedule

Rule 4.4.22 The ETU shall determine and revise as required each market outlook scenario, pre-dispatch schedule scenario and short-term schedule by sequentially running the market clearing engine for each dispatch period specified in Rule 4.4.14, Rule 4.4.16or Rule 4.4.20, as the case may be, using the information described in Rule 4.4.21.

Rule 4.4.23 When preparing each *pre-dispatch schedule scenario*, the *market clearing engine* shall be run for each *dispatch period* from the end of the relevant *dispatch period* for which the *real-time dispatch schedule* used in *Rule 4.4.21(d)(ii)*applies, until the end of the *pre-dispatch horizon* to which such *pre-dispatch schedule scenario* relates*.*

Rule 4.4.24 For pre-dispatch schedules, the market clearing engine is always run from the best current estimates of data.

Rule 4.4.25 When preparing each *short-term schedule*, the *market clearing engine* shall be run for each *dispatch period* from the end of the current *dispatch period*, until the end of the *short-term horizon* to which such *short-term schedule* relates*.*

Rule 4.4.26 For the short-term schedule, the market clearing engine is always run from the best current estimates of data. However, when reporting the actual schedule, only the dispatch periods in the short-term horizon are reported – the initial period that is run in order to get to the start of the short-term horizon is not reported.

Rule 4.4.27 In determining the *scenarios* referred to in *Rule 4.4.22*, each *dispatch period* shall be assumed to be independent of the others except that:

(a) subject to *Rule 4.4.27(b)*, the initial loading of each *generation facility* for each *dispatch period* shall be set equal to the value determined for the end of the preceding *dispatch period* for the relevant *nodal load forecast*; and
(b) the initial loading of each *generation facility* for the first *dispatch period* shall be set in accordance with *Rule 4.4.21(d)*for the relevant *market reference node load forecast*.

Release of Scenario Information

Rule 4.4.28 By 9:00 hours of each *dispatch day* the *ETU* shall, for each *dispatch period* covered by each of the three *market outlook scenarios*:

(a) release to the *dispatch coordinator* for each *registered facility* the projected schedules for *energy*, *regulation* and *reserve*, by *reserve class*, for that *registered facility*;
(b) *publish* the information described in *Rule 4.4.31*; and
(c) communicate to the *ETU* the projected schedules for *energy*, *regulation* and *reserve*, by *reserve class*, for each *registered facility*, together with the information described in *Rule 4.4.31*, in accordance with the *system operation manual* and any applicable *market manual*.

Rule 4.4.29 Not later than 15 minutes prior to the commencement of the first *dispatch period* of each of the three *pre-dispatch schedule scenarios,* the *ETU* shall, for each *dispatch period* included in each of those three *pre-dispatch schedule scenarios*;

(a) release to the *dispatch coordinator* for each *registered facility* the projected schedules for *energy*, *regulation* and *reserve*, by *reserve class*, for that *registered facility;*
(b) *publish* the information described in *Rule 4.4.31*; and
(c) communicate to the market participants the projected schedules for *energy*, *regulation* and *reserve*, by *reserve class*, for each *registered facility*, together with the information described in *Rule 4.4.31*, in accordance with the *system operation manual* and any applicable *market manual*.

Rule 4.4.30 Not later than 25 minutes prior to the commencement of the first *dispatch period* of the *short-term schedule*, the *ETU* shall, for each *dispatch period* included in the *short-term schedule:*

(a) release to the *dispatch coordinator* for each *registered facility* the projected schedules for *energy*, *regulation* and *reserve*, by *reserve class*, for that *registered facility;*
(b) *publish* the information described in *Rule 4.4.31*; and

(c) communicate to the *market participants* the projected schedules for *energy*, *regulation* and *reserve*, by *reserve class*, for each *registered facility*, together with the information described in *Rule 4.4.31*, in accordance with the *system operation manual* and any applicable *market manual*.

Rule 4.4.31 The *ETU* shall *publish* the following information for each *dispatch period* and for each *market outlook scenario, pre-dispatch schedule scenario* and *short-term schedule*:

(a) the projected total *load*;
(b) the projected total transmission losses;
(c) total *reserve* requirements by *reserve class*;
(d) total *regulation* requirements;
(e) projected *energy* prices associated with each *market network node* at which a *generation registered facility* or *generation settlement facility* is located;
(f) the projected *System Marginal Price or Uniform Ghana energy price*;
(g) projected *reserve prices* for each *reserve class* and *reserve provider group*;
(h) projected *regulation prices*;
(i) any forecasted system *energy* shortfalls;
(j) any forecasted system *reserve* shortfalls, by *reserve class*;
(k) any forecasted system *regulation* shortfalls; and
(l) a list of *security constraints* and *generation fixing constraints* applied.

Rule 4.4.32 The *market outlook scenarios*, *pre-dispatch schedule scenarios* and *short-term schedules* reflect indicative forecasts which are released for information purposes only and are not binding on the *ETU* or any *market participant*.

4.1.1 Comment on Section 4.4 of the DEMR

Section 4.4 provides standard rules for the required pre-dispatch activities. There are no inherent flaws, omissions or inconsistencies.

Commitment

In their current state the DEMR do not provide a mechanism for the Dispatcher to commit generation capacity. Presumably the Dispatcher could relay on Article 10.95 of the National Electricity Grid Code to order plants to start. However, this presupposes that an Emergency Condition has already been declared.

Markets in the United States and elsewhere have typically included in their design the ability for the Dispatcher to commit, i.e. bring capacity on line, generation units prior to real time in order to avoid an emergency.

As an example, consider the following language adopted by the Midwest ISO with respect to the Reliability Assessment Commitment process:

40.1 Reliability Assessment Commitment (RAC)[45]

This Section contains the RAC procedures the Transmission Provider will follow using SCUC to commit Resources to meet forecast Energy and Operating Reserve Requirements in each Hour of the SCUC Instructed Hours of Operation based on Market Participants' Offers submitted in the Real-Time Energy and Operating Reserve Market. The RAC processes are as follows:

(i) Any RAC process conducted prior to the Day-Ahead Energy and Operating Reserve Market,
(ii) The RAC process conducted after the posting of the Day-Ahead Energy and Operating Reserve Market results on the Day prior to the Operating Day, and
(iii) Any intra-Day Operating Day RAC process.

40.1.1 Transmission Provider Obligations

The Transmission Provider in its role as the Energy and Operating Reserve Market Operator shall provide the following services for the Real-Time Energy and Operating Reserve Market.

i. Establish and post on the internet, rules and procedures, including Offer rules, for eligibility to participate in the RAC process in the Real-Time Energy and Operating Reserve Market.
ii. Establish and post Offer rules for RAC, as such rules are set forth in Section 40.
iii. Commit Resources to provide Energy and Operating Reserve in the Real-Time Energy and Operating Reserve Market based on, but not limited to, system reliability needs, system operational considerations, and the use of a SCUC algorithm to determine the least costly means of supplying the Capacity required to serve the forecast demand and satisfy the Operating Reserve Requirements.

The selection will be communicated either electronically or through other means to the Market Participants. Virtual Transactions and Resources on either planned or forced outages are not permitted to participate in any RAC process in the Real-Time Energy and Operating Reserve Market.

40.1.2 RAC Resource Offer Obligation

[45] Open Access Transmission, Energy And Operating Reserve Markets Tariff for the Midwest Independent Transmission System Operator, Inc.

a. ***Designated Capacity Resource Obligation – Energy and Contingency Reserve.*** *Consistent with Section 69.2.3, Market Participants with designated Capacity Resources must submit, for any portion of a Resource designated as a Capacity Resource, a Self-Schedule or Offer for Energy and Contingency Reserve. Such Offers shall be consistent with the requirements specified in Section 40 and in the Business Practices Manuals. This designated Capacity Resource must Offer obligation applies to all RAC processes executed prior to the Operating Day as specified in Module E of this Tariff, except to the extent that the designated Capacity Resource is unavailable to provide Energy or Contingency Reserve due to a forced or planned outage or other physical operating restriction consistent with this Tariff.*

b. ***Transitional Designated Capacity Resource Obligation – Regulating Reserve.*** *Market Participants with designated Capacity Resources must submit, for any portion of a Resource designated as a Capacity Resource, an Offer for Regulating Reserve if a Regulation Qualified Resource, provided that, such must-offer requirement shall terminate one hundred eighty (180) days after the implementation of the Energy and Operating Reserve Markets.*

Such Offers shall be consistent with the requirements specified in this Section and in the Business Practices Manuals. This transitional obligation applies to all RAC processes executed prior to the Operating Day, except to the extent that the designated Capacity Resource is unable to provide Regulating Reserve due to a forced or planned outage or other physical operating restrictions consistent with this Tariff.

c. ***Releasing Designated Capacity Resource Obligation.*** *The Market Participants are released from the must Offer obligation if not committed in the Day-Ahead Energy and Operating Reserve Market or any RAC process prior to the Operating Day. The Transmission Provider may curtail Market Participants' Export Schedules sourced from designated Capacity Resources during the Operating Day for Emergencies or to maintain Midwest ISO Balancing Authority Area reliability. Procedures for such Curtailments shall be specified in the Business Practices Manuals.*

d. ***Non-designated Capacity Resource Obligation.*** *A Market Participant shall not have the obligation to Offer Energy* *and Operating Reserve into the Energy and Operating Reserve Markets for any portion of a Resource not designated as a Capacity Resource.*

40.1.3 RAC Data Inputs

The Transmission Provider shall use the data inputs set forth in this Section in executing the RAC process.

a. Load Forecast

The Transmission Provider shall conduct Hourly Load Forecasts for the Transmission Provider Region pursuant to procedures set forth in the Business Practices Manuals.

b. Net Scheduled Interchange

The Transmission Provider shall consider cleared Day-Ahead Interchange Schedules and Real-Time Interchange Schedules when executing the RAC process.

c. Resource Information

Market Participants may, but are not obligated to, submit Offers for any Capacity not selected for a Day-Ahead Schedule. Market Participants must indicate for each Hour of the Operating Day if Resources are to be self-committed. Market Participants whose Resources were not selected for a Day-Ahead Schedule, but are designated as Capacity Resources pursuant to Section 69, are obligated to submit Offers or Self-Schedules into the RAC process conducted the Day prior to the Operating Day after the Day-Ahead Midwest ISO Energy and Operating Reserve Market results are posted. A Market Participant must submit or update their real-time Offers and/or Self-Schedules prior to the execution of the RAC process, which normally occurs at 1600 EST or one hour following the posting of the Day-Ahead Energy and Operating Reserve results, whichever is later.

d. Offer Requirements and Specifications for the RAC Process

A Market Participant intending to supply Energy and Operating Reserve into the RAC process shall submit the information requested in the Real-Time Offer specifications described in Sections 40.2.5 through 40.2.7.

40.1.4 RAC Process

a. Timing

The Transmission Provider will conduct RAC processes as necessary beginning seven (7) Days prior to the Operating Day. The Transmission Provider will conduct a Day-Ahead RAC process sequentially after the closing and publishing of the Day-Ahead Energy and Operating Reserve Market results at 1500 hours EST, or such later time as may be required from time to time due to unanticipated events.

The Day-Ahead RAC rebid process starts at 1500 hours EST or following the posting of the Day-Ahead Energy and Operating Reserve Market results, whichever is greater, and closes one Hour after the posting of the Day-Ahead Energy and Operating Reserve Market results, at which time the Day-Ahead RAC analysis begins. The Transmission Provider will conduct RAC processes as necessary during the Operating Day.

b. RAC Objective Function

The Transmission Provider shall use the RAC process to commit Resources in a manner that minimizes the total Capacity costs to satisfy the Load Forecast and Operating Reserve Requirements using a SCUC algorithm that minimizes the total commitment costs of procuring the Capacity needed to meet one-hundred percent (100%) of the Transmission Provider Load Forecast, Regulating Reserve Requirement, Spinning Reserve Requirement, and Supplemental Reserve requirement while enforcing physical and reliability constraints.

The commitment costs to procure Capacity include all costs based on Start-Up Offers, No-Load Offers, Energy Offer curves up to the Hourly Economic Minimum Limit for Generation Resources and Demand Response Resources Type II, all costs based on Energy Offers, Shut-Down Offers, and Hourly Curtailment Offers for Demand Response Resources-Type I.

c. Notification

The Transmission Provider will notify the Market Participants of those Resources that have been committed in any RAC process sufficiently in advance to enable the Market Participant to comply with RAC obligations, consistent with the design and operating characteristics of such Resources, and will instruct such Market Participants *when to start their Resources and operate at the Hourly Economic Minimum Limit.*

d. Resource Obligations

Resources committed by the Transmission Provider in any RAC process must adhere to instructions on when to start and operate in their normal dispatch range, to the extent feasible, and must submit an Energy Offer and applicable Operating Reserve Offers for the Resource's full Capacity in the Real-Time Energy and Operating Reserve Market regardless of whether all or a portion of the Resource's Capacity is or is not designated as a Capacity Resource.

While having the ability to commit capacity is not necessarily a requirement for a good electricity market, it does enhance the reliability of the system and provides a transparent mechanism for the dispatcher to bring capacity online.

Dispatch

The primary activity in real-time is the creation of a dispatch signal that balances supply and demand and simultaneously relieves any transmission constraints. In a nodal system, like the one in the DEMR, the dispatch signal is the nodal or locational price. Generators and load use these prices to decide whether to increase or decrease their participation in the real-time market.

The Dispatcher monitors the balance of load and generation within system reliability limitations by continuously performing real-time Security Constrained Economic Dispatch (SCED) and sending electronic price signals or set points[46] to generators to indicate their desired output level. The objective function of the SCED program should be to serve the load at the least cost.

While the SCED is, in some sense the dispatch "engine," there are various integrated components and the following diagram "disaggregates" the process[47] of creating a nodal price:

[46] There is no difference between sending a generator a price signal or a physical set point that aligned with their offers.
[47] While this is a standard diagram, this particular example comes from training material produced by PJM.

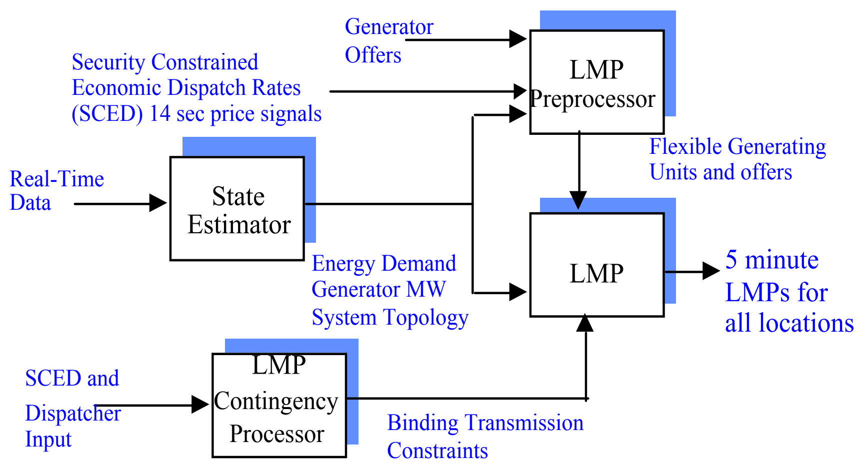

Figure 3: Dispatch Process

As shown in the diagram, the output of the SCED program also serves as an input to the Locational Marginal Pricing Preprocessor. As proposed in the DEMR generators will be paid nodal prices based on their actual output levels, thus they have an economic interest in following the leading (SCED) price signals sent out by the Dispatcher. The SCED price is used to determine the expected output levels, i.e. where a unit should be based upon their offer curve.

The Dispatcher monitor security limits on a continual basis and when a security limit is about to be reached, they use the Locational Marginal Pricing Contingency Processor (LMPCP) – as shown in the previous diagram – to determine the appropriate action to remedy the constraint. The LMPCP provides the Operator with solutions to the constraint ranked by cost per MW impact. Remedies may include reconfiguring the grid, re-dispatch, and curtailing of transactions or dispatchable load. These solutions are compared to the proposed Energy Management System (EMS) solution based upon the SCED algorithm. If the Dispatcher agrees with the SCED solution, no manual intervention will be necessary. If the Dispatcher disagrees with the SCED solution, the Dispatcher can override the SCED/EMS solution. The LMPCP module will also include an electronic log, which provides an audit trail to ensure the actions taken by the Dispatcher are consistent with the objective function of least cost dispatch.

If the appropriate SCED/EMS/Dispatcher action is to run out-of-merit order generation, the nodal prices will disperse and there will not be a single System Marginal Price.

The State Estimator is used to provide a complete and consistent solution for both the observable and unobservable portions of the electrical network. The output of the State Estimator is used in both the SCED computer program as well as the LMP program. Data redundancy and the underlying physical and mathematical relationships provide a solution with less error than the original measurements. The State Estimator can correct bad data and calculate missing data in the model. The ETU/Dispatcher will need to ensure that the number of observable points on the system are sufficient to provide the accuracy needed to use nodal pricing as the dispatch signal.

In summary, the fundamental activity that takes place in real time is the production of a dispatch signal, i.e. a nodal price that maintains reliability, relieves transmission constraints and balances supply and demand. This is accomplished through the SCED process and the creation of Locational Marginal Prices.

Section 4.5 along with Appendices 4B – F of the DEMR details the relevant dispatch rules:

SECTION 4.5 - DISPATCH AND PRICING IN THE REAL TIME

Market Administrator Responsibilities in Real Time

Rule 4.5.01 The *MA* shall, prior to each *dispatch period* and in accordance with the *market operations timetable,* take the following actions so as to ensure *dispatch related data* are current and available to the *ETU*:

(a) conduct such studies as may be necessary to determine the appropriate parameters to be used as inputs to the *market clearing engine* for the upcoming *dispatch period*; and

(b) determine or update, as the case may be, the *dispatch related data* referred to in Appendix 4E for the *dispatch period.*

ETU Responsibilities in Real-Time

Preparation for Real-Time Dispatch

Rule 4.5.02 The *ETU* shall for each *dispatch period* and in accordance with the *market operations timetable*:

(a) revise as required the most current *market reference node load forecast;* and

(b) determine and communicate *real-time dispatch schedules* in accordance with *the real -time scheduling process.*

Rule 4.5.03 In the event that the *ETU* forecasts a shortfall of *energy* for any *dispatch period* within the first two hours of the market outlook horizon, the *ETU* shall immediately adjust the *nodal load forecasts* described in *Rule 4.4.06*(a) for the corresponding *dispatch periods* to reflect the shortfall quantities and locations specified by the *ETU*.

Rule 4.5.04 Notwithstanding Section 1.12, no *market participant* shall be entitled to compensation from the *ETU* for any financial loss sustained by the *market participant* due to the *market participant* having been *dispatched* on the basis of *load* as forecasted pursuant to *Rule 4.5.02 to Rule 4.5.10*rather than on the basis of actual *load.*

The Real-Time Scheduling Process

Rule 4.5.05 The *ETU* shall, prior to the commencement of each *dispatch period* and in accordance with the *market operations timetable*, use the *market clearing engine* to determine for that *dispatch period*:

(a) a *real-time dispatch schedule*, containing schedules of *energy*, *reserve* and *regulation* for *registered facilities,* to be released to the market participants which shall be deemed to constitute the *dispatch instructions* issued by the *ETU* to the applicable *dispatch coordinators* unless and until further *dispatch instructions* are issued by the *ETU* to a given *dispatch coordinator*; and

(b) a*real-time pricing schedule* determined by the *market clearing engine*, including:

(i) the *System Marginal Price or Uniform Ghana Electricity Price*;

(ii) *reserve* prices for each *reserve class* and for each *reserve provider group*; and

(iii) *regulation* prices.

Rule 4.5.06 The *ETU* shall use the following information to determine the *real-time dispatch schedule* and *real-time pricing schedule* described in *Rule 4.5.05* using the most current valid information:

(a) *offers* for the relevant *dispatch period* held by the *ETU*;

(b) *standing capability data* for the relevant *dispatch period* held by the *ETU*;

(c) the *market reference node load forecast*, adjusted where applicable;

(d) the *import* and *export limits*;

(e) such other parameters or data as may be required to enable the *market clearing engine* to determine the required outputs.

Rule 4.5.07 The *ETU* shall, in accordance with the *market operations timetable*, release to the *dispatch coordinator* for each *registered facility* a *real-time dispatch schedule* comprising that portion of the *real-time dispatch schedule* that describes the quantities of *energy, reserve* by *reserve class* and *regulation* scheduled in respect of that *registered facility*.

Rule 4.5.08 The *ETU* shall, in accordance with the *market operations timetable*, *publish* the following information as it pertains to each *dispatch period:*

(a) total *load;*

(b) total transmission losses;

(c) total *reserve* requirements by *reserve class*;

(d) total *regulation* requirements; the *System Marginal Price or reference Uniform Ghana Electricity Price*;

(e) *reserve prices* for each *reserve class* and *reserve provider group*;

(f) *regulation prices*;

(g) any system *energy* shortfalls reported by the *market clearing engine*;

(h) any system *reserve* shortfalls, by *reserve class,* reported by the *market clearing engine*;

(i) any system *regulatio*n shortfalls reported by the *market clearing engine*; and

(j) a list of *security constraints* and *generation fixing constraints* applied.

Rule 4.5.09 The quantities specified in a *real-time dispatch schedule* shall be considered firm in the sense that:

(a) they are deemed to be the *dispatch instructions* for each *registered facility* unless and until further *dispatch instructions* are issued by the *ETU* to the *dispatch coordinator* for a given *registered facility*;

(b) *market participants* shall comply with the *dispatch instructions* referred to in *Rule 4.5.09(a)*unless forced to deviate from those *dispatch instructions* under the conditions referred to in and to the extent permitted by the *grid code*.

Rule 4.5.10 In the event the *market clearing engine* fails to produce any *real-time pricing schedule* for a particular *dispatch period* for any reason other than due to the suspension of *real time market*, then the *ETU* shall issue a price revision *advisory* as if for provisional prices confirmed to be subject to revision. In such circumstances, the prices for the affected *dispatch period* for which no *real-time pricing schedule* was produced shall be determined.

Market Advisories

Rule 4.5.11 The *ETU* shall issue, as soon as practicable and in such manner as will provide adequate notice, using electronic means or in the case where electronic means are not available, by any other means it considers suitable, *advisory notices* pertaining to the incidence and extent of any of the following events for any *dispatch period* included in the current *market outlook horizon* in respect of which such event is indicated by the *market outlook scenarios, pre-dispatch schedule scenarios* and *short-term schedule*, and containing the applicable information described in Appendix 4F:

(a) any *energy* surplus;
(b) any *energy* shortfalls;
(c) any *reserve* shortfalls, by *reserve class*; and
(d) any *regulation* shortfalls.

Rule 4.5.12 The *ETU* shall issue, as soon as practicable and in such manner as will provide adequate notice, using electronic means, or in the case where electronic means are not available, by any other means it considers suitable, and containing the applicable information described in Appendix 4F:

(a) system status *advisory notices* for the current *dispatch period*, any *dispatch period* of the current *short-term horizon* or any *dispatch period* of the current *pre-dispatch horizon* in respect of which it has been informed by the *ETU* that a major equipment *outage, load shedding* or other abnormal condition on the *ETU controlled system* that the *ETU* considers material is occurring or is likely to occur;

(b) communications warning *advisory notices* for the current *dispatch period*, any *dispatch period* of the current *short-term horizon* or any *dispatch period* of the current *pre-dispatch horizon* in respect of which *market participants* are experiencing, or the *ETU* considers that there is a significant probability that *market participant*s will experience, difficulties in delivering communications to, or receiving communications from, the *ETU*, or that the *ETU* will experience, difficulties in delivering communications to, or receiving communications from, the *market participants*; and

(c) price warning *advisory notices* for the current *dispatch period*, any *dispatch period* of the current *short-term horizon,* any *dispatch period* of the *pre-dispatch horizon* or any *dispatch period* of the *market outlook horizon* for which the prices calculated or released to *market participant*s may be subject to revision.

Rule 4.5.13 The *ETU* shall provide confirmation by 12.00 noon each day, in such manner as will provide adequate notice, using electronic means, or in the case where electronic means are not available, by any other means it considers suitable, as to whether prices determined for the previous *dispatch day* are final or provisional. Provisional prices may be subject to revision.

Rule 4.5.14 For provisional prices which are confirmed to be subject to revision, and where *Rule 4.5.16* does not apply, the *ETU* shall issue, as soon as possible but no later than 2 *business days* prior to the time at which the *preliminary settlement statements* for the relevant *dispatch day* must be issued in accordance with *Rule 5.5.03*, price revision *advisory notices* for the relevant *dispatch day* in such manner as will provide adequate notice, using electronic means, or in the case where electronic means are not available, by any other means it considers suitable, and containing the applicable information in Appendix 4F.

Rule 4.5.15 Provisional prices in respect of which no such price revision advisory notices are issued by the deadline stipulated above shall be deemed final.

Rule 4.5.16 Where *constraint violation costs* have been applied by the *market clearing engine* in respect of any *dispatch period*, the *ETU* shall declare the prices for that *dispatch period* to be provisional.

Rule 4.5.17 Where prices in respect of any *dispatch period* have been declared to be provisional, the *ETU* shall request that the *MA* confirm whether or not *load shedding* had occurred during that *dispatch period* and provide to the *ETU* the maximum actual line flow values of such lines as identified by the *ETU* for that *dispatch period*.

Rule 4.5.18 If the *ETU* confirms that *load shedding* had not occurred in the *dispatch period*, the *ETU* shall issue a price revision *advisory notice* for that *dispatch period* no later than 2 *business days* prior to the time at which the *preliminary settlement statements* for the relevant *dispatch day* must be issued in accordance with *Rule 5.5.03*, in such manner as will provide adequate notice, using electronic means, or in the case where electronic means are not available, by any other means it considers suitable, and containing the applicable information in Appendix 4F.

Rule 4.5.19 Provisional prices in respect of which no such price revision *advisory notices* are issued by the deadline stipulated above shall be deemed final.

Rule 4.5.20 The *ETU* shall, as soon as practicable, withdraw any of the *advisory notices* and issued in respect of a *dispatch period* to the extent that the conditions referred to in such *advisory notices* are no longer or are expected to no longer be applicable to such *dispatch period*.

Rule 4.5.21 Where the *ETU* issues a communications warning *advisory notice*, it shall use all reasonable endeavours to promptly restore communications, establish alternative means of communication or avoid the communications problem anticipated in the *advisory notice*, as the case may be.

APPENDIX *4B* - INPUT DATA FOR THE MARKET CLEARING ENGINE

B.1.1 INTRODUCTION

B.1.2 The information described in Sections B.2 to B.9 of this Appendix shall be used as input data for the *market clearing engine* for each *dispatch period* for which the *market clearing engine* is required to produce schedules and prices.

B.2 MARKET PARTICIPANT DATA

B.2.1 All valid *energy offers* from *registered facilities* for that *dispatch period*.

B.2.2 All valid *reserve offers* for each *reserve class* from *registered facilities* for that *dispatch period*.

B.2.3 All valid *regulation offers* from *registered facilities* for that *dispatch period*.

B.2.4 All valid *standing capability data* corresponding to *registered facilities* for the *trading day* within which to that *dispatch period* occurs.

B.3 NODAL LOAD FORECAST

B.3.1 The relevant *nodal load forecast* prescribed in the provisions of Chapter 4.

B.4 INTERTIE SCHEDULE DATA

B.4.1 For each *intertie*, up to ten *price-quantity pairs*, represented as included in an *energy offer*, where the *price-quantity pairs* shall be specified by the *ETU* so that the schedules produced by the *market clearing engine* will reasonably correspond to the scheduled flow as provided by market participants into Ghana on the *intertie* for that *dispatch period* to the extent that it is possible for the *market clearing engine* to produce such an outcome.

B.4.2 For each intertie, up to ten *price-quantity pairs*, represented as included in an *energy bid* except that the prices shall decrease with increasing cumulative quantity, where the *price-quantity pairs* shall be specified by the *ETU* so that the schedules produced by the *market clearing engine* will reasonably correspond to the scheduled flow as provided by market participants out of Ghana on the *intertie* for that *dispatch period* to the extent that it is possible for the *market clearing engine* to produce such an outcome.

Explanatory Note: Interchange schedules will be represented as a dummy market participant with imports represented as a conventional energy offer while exports are represented as a dispatchable load energy bid would be represented, i.e. like an energy offer but as prices increase then less MWs are scheduled, not more. The price-quantity pairs could be defined so that the schedule only deviated from the desired flow if prices went to their maximum or minimum levels (i.e. shortage or over-supply). Thus the *market clearing engine (*MCE), would always schedule the required flow unless there was not enough generation to supply power for export, or not enough load to consume imported power. The availability of ten price-quantity pairs does allow for more price sensitive schedules if these are ever required.

B.5 <u>ETU CONTROLLED GRID DATA</u>

B.5.1 The set of *dispatch network lines* that are in service in that *dispatch period* as specified by the *MA* in accordance with Appendix 4D.

B.5.2 The resistance, reactance and fixed losses for each *dispatch network line* that is in service in that *dispatch period* as specified by the *ETU* in accordance with Appendix 4D.

B.5.3 The thermal line ratings and operational flow limits on each *dispatch network line* for each direction of flow for that *dispatch period* as specified by the *ETU* in accordance with Appendix 4D.

B.5.4 An estimate of the reactive power flows on each *dispatch network line* for that *dispatch period* as specified by the *ETU* in accordance with Appendix 4D.

B.6 GENERATOR DATA

B.6.1 Initial output levels for each *generation registered facility* as at the start of that *dispatch period* as specified by the *ETU* in accordance with Appendix 4D.

B.6.2 The set of all *generation fixing constraints* and such additional *generic constraints* as may be specified by the *ETU* in accordance with Appendix 4E to apply within that *dispatch period*.

B.7 SECURITY, RESERVE AND REGULATION DATA

B.7.1 The set of all *security constraints* specified by the *ETU* in accordance with Appendix 4E to apply within that *dispatch period*.

B.7.2 The set of *reserve provider groups* with the *reserve class* and the set of *registered facilities* to which each such *reserve provider group* is associated as specified by the *ETU* in accordance with Appendix 4E for that *dispatch period*.

B.7.3 Piece-wise linear effectiveness functions specified by the *ETU* in accordance with Appendix 4E for each *reserve provider group*, describing the expected effectiveness of different levels of *reserve* quantity scheduled from that *reserve provider group* for that *dispatch period*.

B.7.4 The minimum required *reserve* for each *reserve class* specified by the *ETU* in accordance with Appendix 4E for that *dispatch period*.

B.7.5 For each *reserve class*, a risk adjustment factor specified by the *ETU* in accordance with Appendix 4E that scales the contingency risk determined within the *market clearing engine* to reflect special conditions within that *dispatch period*.

B.7.6 The minimum required *regulation* specified by the *ETU* in accordance with Appendix 4E for that *dispatch period*.

B.8 VIOLATION COST AND PRICE CAP DATA

B.8.1 *Constraint violation costs* as established by the *ETU* in accordance with Section 2.3 of this Chapter 4, where the specific values to apply in that *dispatch period* shall be specified by the *ETU* in accordance with Appendix 4D.

B.8.2 The *settlement* price limits.

B.9 MARKET CLEARING ENGINE PARAMETERS

B.9.1 Such parameters as may be required to indicate the sources of input data and the destinations of output data for the production of each of the *market outlook scenarios*, the *pre-dispatch schedule scenarios*, the *short-term schedule* and the *real-time dispatch schedule*.

APPENDIX *4C* - OUTPUT DATA FROM THE MARKET CLEARING ENGINE

C.1 INTRODUCTION

C.1.1 The *market clearing engine* shall produce, at minimum, the outputs described in sections C.2 to C.4 of this Appendix.

C.2 REGISTERED FACILITY AND INTERTIE SPECIFIC QUANTITIES

C.2.1 The *market clearing engine* shall produce end-of-*dispatch period* target values for the following *physical services* for each *registered facility* that has associated with it a valid *offer* to provide that *physical service*:

C.2.1.1 the amount of *energy* scheduled to be injected onto the *transmission system*, expressed in MW;

C.2.1.2 the amount of *reserve*, for each *reserve class*, scheduled to be provided, expressed in MW; and

C.2.1.3 the amount of *regulation* scheduled to be provided, expressed in MW.

C.2.2 The *market clearing engine* shall produce end-of-*dispatch period* target values for the *energy* to be injected onto, or withdrawn from, the *transmission system* in each *dispatch period* on each *intertie*, expressed in MW.

C.3 PRICES

C.3.1 The *market clearing engine* shall produce the following prices for each *dispatch period*:

C.3.1.1 The *market energy price* or *MEP* for each *market network node,* expressed in GH¢/MWh;

C.3.1.2 the Uniform Ghana Electricity Price or *UGEP,* expressed in GH¢/MWh;

C.3.1.3 the price of *reserve* for each *reserve class*, expressed in GH¢/MWh;

C.3.1.4 the *market reserve price* or *MRP* for each *reserve provider group*, expressed in GH¢/MWh*;* and

C.3.1.5 *market regulation price* or *MFP*, expressed in GH¢/MWh.

C.4 ADDITIONAL DATA

C.4.1 The *market clearing engine* shall, at a minimum, produce the following information for each *dispatch period*:

C.4.1.1 the total *load* scheduled to be supplied at each *dispatch network node* and in aggregate, expressed in MW;

C.4.1.2 the total generation scheduled at each *generation registered facility* and in aggregate, expressed in MW;

C.4.1.2A the total transmission losses in the system, expressed in MW;

C.4.1.3 the extent of any shortfall in *energy*, by *dispatch network node* and in aggregate, expressed in MW;

C.4.1.4 the extent of any surplus in *energy*, by *dispatch network node* and in aggregate, expressed in MW;

C.4.1.4A the total *reserve* requirement by *reserve class*, expressed in MW;

C.4.1.5 total *reserve* scheduled to supply each *reserve class*, from each *reserve provider group* and in aggregate, expressed in MW;

C.4.1.6 the extent of any shortfall in *reserve*, by *reserve class*, expressed in MW;

C.4.1.4A the total *regulation* requirement, expressed in MW;

C.4.1.7 total *regulation* scheduled, expressed in MW;

C.4.1.8 the extent of any shortfall in *regulation,* expressed in MW;

C.4.1.9 predicted power flows and *energy* losses on *dispatch network lines*, expressed in MW;

C.4.1.10 a list of *security constraints* and *generation fixing constraints* applied;

C.4.1.11 details of the extent of any constraint violations; and

C.4.1.12 the value, in cedis, of the objective function to be specified for the MCE.

APPENDIX *4D* – STANDING CAPABILITY DATA AND OFFERS

D.1 GENERATION FACILITY DATA

D.1.1 The *standing capability data* pertaining to a *generation facility* shall include:

D.1.1.1 information sufficient to indicate the *generation facility* to which the *standing capability data* pertains;

D.1.1.2 the maximum generation capacity, in MW, of the *generation facility*;

D.1.1.3 the maximum ramp-up rate for the *generation facility* in MW/minute;

D.1.1.4 the maximum ramp-down rate for the *generation facility* in MW/minute;

D.1.1.5 the maximum *reserve* capacity of the *generation facility* for each *reserve class* which the *generation facility* is or seeks to be registered to provide;

D.1.1.6 the maximum combined *generation capacity* and *reserve* capacity for each *reserve class* for which the *generation facility* is or seeks to be registered to provide;

Explanatory Note – The previous clause allows the market participant to specify a capacity limit for the purpose of providing reserve which exceeds the facilities normal, sustainable, capacity.

D.1.1.7 if the *generation facility* is or seeks to be registered to provide any *reserve class*, the reserve proportion, which constrains the maximum reserve that may be scheduled from the *generation registered facility* to the specified ratio of energy scheduled for the *generation registered facility*. The reserve proportion should be specified to minimise the likelihood of the *generation registered facility* being scheduled to provide reserve in excess of what can reliably be provided at any given level of scheduled energy;

D.1.1.8 the maximum *regulation* capacity of the *generation facility* if the *generation facility* is or seeks to be registered to provide *regulation*;

D.1.1.9 the maximum *energy* output at which *automatic generator control* or *AGC* can operate the *generation facility* if the *generation facility* is or seeks to be registered to provide *regulation*;

D.1.1.10 the minimum output at which *automatic generator control* or *AGC* can operate the *generation facility* to provide *regulation* capability if the *generation facility* is or seeks to be registered to provide *regulation*;

D.1.1.11 the time delay in seconds before the *generation facility* begins to respond following the standard contingency event specified in the *system operation manual*;

D.1.1.12 the lowest *energy* output level that the *generation facility* is capable of providing *reserve* for all *reserve class*; and

D.1.1.13 the *reserve* capacity of the *generation facility* at low, medium and high *energy* output level for each *reserve class* which the *generation facility* is or seeks to be registered to provide.

D.2 LOAD FACILITY DATA

D.2.1 The *standing capability data* pertaining to a *load facility* which is or seeks to be registered to provide *reserve* shall include:

D.2.1.1 information sufficient to identify the *load facility* to which the *standing capability data* pertains; and

D.2.1.2 the maximum *reserve* capacity of the *load facility* for each *reserve class* that the *load facility* is or seeks to be registered to provide.

D.3 SUBMISSION OF STANDING CAPABILITY DATA

D.3.1 When a *market participant* applies to register a facility under Section 2.5, it shall at the same time submit that facility's initial *standing capability data* to the *ETU* for approval.

D.3.2 If there is a change in the physical capability of a *registered facility*, its *dispatch coordinator* shall submit revised *standing capability data* as necessary to reflect the change, to the *ETU* for approval.

D.3.3 *Standing capability data* shall:

D.3.3.1 comply with the requirements of Section D.1 and Section D2 of this APPENDIX;

D.3.3.2 be submitted to the *ETU* in the form specified by the *system operation manual*; and

D.3.3.3 in the case of revised *standing capability data*, be submitted to the *ETU* within the time specified by the *system operation manual*.

D.3.4 If the *ETU* requires a *dispatch coordinator* to provide revised *standing capability data*, the *dispatch coordinator* shall do so within the time specified by the *ETU*.

D.4 APPROVAL OR REJECTION OF STANDING CAPABILITY DATA

D.4.1 If any initial *standing capability data* submitted by a *market participant* or revised *standing capability data* submitted by a *dispatch coordinator* is:

D.4.1.1 approved by the *ETU*; or

D.4.1.2 rejected by the *ETU*,

the *ETU* shall notify the *market participant* or the *dispatch coordinator* (as the case may be) of the approval or in the case of rejection, with reasons for the rejection.

D.5 CONFIRMATION OF RECEIPT OF STANDING CAPABILITY DATA

D.5.1 When the *ETU* receives and approves the *standing capability data*, the *ETU* shall:

D.5.1.1 confirm receipt to the *market participant* or *dispatch coordinator* who submitted the *standing capability data* (as the case may be) in the manner and within the time specified in the applicable *market manual*; and

D.5.1.2 create or update, as applicable, its records of that relevant *standing capability data* to be used by the *market clearing engine* in accordance with the applicable *market manual*.

D.5.2 If a *market participant* or *dispatch coordinator* (as the case may be) does not receive confirmation of receipt of *standing capability data*, it must immediately notify the *ETU* in accordance with the applicable *market manual*.

D.6 HOW STANDING CAPABILITY DATA IS USED

D.6.1 The *ETU* shall use the *standing capability data* held in its records to produce *market schedules*.

D.6.2 For a given *dispatch period*, if a *registered facility*'s revised *standing capability data*:

D.6.2.1 is not communicated to the *ETU* in time to allow the *ETU* to revise its records; or

D.6.2.2 is rejected by the *ETU*,

the *ETU* shall use that *registered facility*'s last approved *standing capability data* held in the *ETU*'s records to produce *market schedules* for that *dispatch period*.

D.7 SUBMISSION OF STANDING OFFERS

D.7.1 Every market participant shall appoint a dispatch coordinator who shall be responsible for data submission between the market participant and the ETU.

D.7.2 The *ETU* shall, prior to the *market commencement date*, establish, *publish* in the applicable *market manual* and implement a process for the submission and validation of the following data:

D.7.2.1 *standing offers* for *energy*, *reserve* and *regulation*; and

D.7.2.2 *offer variations* for *energy*, *reserve* and *regulation*.

D.7.3 Standing offers shall be prices that reflect the SRMC of a generating facility for the purposes of dispatch.

D.7.4 Offer variations shall be submitted and validated via computer without human intervention.

D.7.5 Modifications to standing capability data will be quite infrequent and the data in question must be certified by the ETU, so this information will be entered manually by the ETU.

D.7.6 Validation by the *ETU* of *standing offers*, *offer variations* and *standing capability data* shall be limited to determining whether:

D.7.6.1 they are in the form and contain the information required by the *market rules* and any applicable *market manual*;

D.7.6.2 they are submitted in the manner and within the time prescribed by the *market rules* and any applicable *market manual*;

D.7.6.3 in the case of *standing capability data*, it has been approved by the *ETU* in accordance with Section D.6.2 of this APPENDIX; and

D.7.6.4 in the case of *standing offers* and *offer variations*, they are in accordance with the corresponding *standing capability data* to the extent described in Sections 5.2 to 5.4.

D.7.7 The applicable *dispatch coordinator* shall be responsible for ensuring that such *standing offers*, *offer variations* and *standing capability data* comply with the *market rules* and all applicable *market manuals.*

APPENDIX *4E* – DISPATCH RELATED DATA

E.1 <u>INTRODUCTION</u>

E.1.1 The information listed in Sections E.2 to E.7 of this Appendix describes the *dispatch related data* referred to in Sections 6.1 and 8.1

of this Chapter 4 which must be communicated to the *ETU* in accordance with those Sections and the applicable *market manuals*. Except as otherwise specified in these *market rules,* the *ETU* shall utilise the latest *dispatch related data* received from the *market participants*. In the event that such latest *dispatch related data* is not uploaded in time for the imminent *market clearing engine* run, the *ETU* shall utilise the latest available and uploaded *dispatch related data* for that *market clearing engine* run.

E.2 LOAD DATA

E.2.1 The *ETU*'s expectation of *non-dispatchable load* for each *dispatch period* within the *market outlook horizon*.

E.2.2 The *ETU*'s expectation of *dispatch periods* in which there exists a serious risk of any of an *energy*, *reserve* or *regulation* shortfall or of an *energy* surplus within the *market outlook horizon*, together with the amount of the shortfall in each period, and in the case of energy shortfalls, the expected *dispatch network nodes* at which the shortfall will occur.

E.2.3 The actual distribution of *non-dispatchable load* over all the *dispatch network nodes* for the current *dispatch period.*

E.3 GENERATOR DATA

E.3.1 The *ETU*'s expectation of the MW *energy* output level of each *generation unit* as at the beginning of the upcoming *dispatch period*.

E.3.2 Any *generation fixing constraints* to be applied in respect of the output level of each *generation registered facility* for each *dispatch period* in the *market outlook horizon*.

E.3.3 Any additional *generic constraints* to be applied in respect of the output level of any group of *generating units* for the purpose of reflecting real limitations on those *generation units* for each *dispatch period* in the *market outlook horizon*.

Explanatory Note: Generation fixing constraints are a special class of constraints, having the form of security constraints, imposed directly by the *market clearing engine (MCE)* on an individual generating facilities output (e.g. to limit output of a generator to a level suitable for voltage support). The additional constraints referred to in the previous clause have the same form as security constraints but may be applied to reflect physical constraints on groups of facilities at a location. These constraints may be required to address real-time outages etc., which are not strictly security related.

E.4 TRANSMISSION DATA

E.4.1 The set of *dispatch network lines* that are in service in each *dispatch period* of the *market outlook horizon*.

E.4.2 The thermal line ratings for each *dispatch network line,* for each *dispatch period* of the *market outlook horizon*.

E.4.3 The operational flow limits on each *dispatch network line* for each direction of flow for each *dispatch period* of the *market outlook horizon*.

E.4.4 The resistance, reactance and fixed losses for each *dispatch network line,* for each *dispatch period* of the *market outlook horizon*.

E.4.4A For the phase-shifting transformer of each *phase-shifting transformer line*:

(a) the phase angle shift per one tap position change;

(b) the minimum and maximum tap positions; and

(c) the tap position that results in zero degree phase angle shift,

for each *dispatch period* of the *market outlook horizon*; and

(d) the latest tap position of the phase-shifting transformer. The market participants shall provide this value to the *ETU* before the start of each *dispatch period.*

E.4.5 The *intertie schedules* for all *interties* in each *dispatch period* of the *market outlook horizon.*

E.4.6 The *ETU's* estimate of the reactive power flows on each *dispatch network line* in service in each *dispatch period* of the *market outlook horizon*.

E.4.7 Such other information as may be required to represent the *dispatch network* for each *dispatch period* of the *market outlook horizon*.

E.4.8 The connection status of the *intertie* lines for each *dispatch period* of the *market outlook horizon*.

E.5 SECURITY, RESERVE AND REGULATION DATA

E.5.1 The set of all *security constraints* limiting combinations of *dispatch network line* flows, *generation registered facility* output levels and net injections at each *dispatch network node* for each *dispatch period* of the *market outlook horizon*.

E.5.2 The set of *reserve provider groups* with the *reserve class* and the set of *registered facilities* to which each such *reserve provider group* is associated applicable for each *dispatch period* of the *market outlook horizon*.

E.5.3 The piece-wise linear effectiveness functions for each *reserve provider group*, describing the expected effectiveness of different levels of *reserve* quantity scheduled from that *reserve provider group* for each *dispatch period* of the *market outlook horizon*.

E.5.3.A The set of *reserve provider zones* with the *reserve class* to which each such *reserve provider zone* is associated applicable for each *dispatch period* of the *market outlook horizon*.

E.5.3.B For each *reserve provider zone* the maximum *reserve* response for each *dispatch period* of the *market outlook horizon*

E.5.3C For each *reserve class*, the maximum proportion of the risk for that class that can be covered by *reserve* provided by *load registered facilities,* for each *dispatch period* of the *market outlook horizon*

E.5.4 The minimum required *reserve* for each *reserve class* for each *dispatch period* of the *market outlook horizon*.

E.5.5 For each *reserve class*, a risk adjustment factor that scales the contingency risk determined within the *market clearing engine* to reflect special conditions within each *dispatch period* of the *market outlook horizon*.

E.5.6 The minimum required *regulation* for each *dispatch period* of the *market outlook horizon*.

E.5.7 An estimated *intertie* contribution factor that represents the assistance provided by the *intertie* in the event of a frequency drop, when one or more of the *interties* are connected.

E.5.8 For each *reserve class*, the ratio of the maximum acceptable frequency deviation to the nominal frequency, for the situation where one or more of the *interties* are connected.

E.5.9 For each *reserve class*, the ratio of the maximum acceptable frequency deviation to the nominal frequency, for the situation where none of the *interties* are connected.

E.5.10 For each *reserve class*, an estimated load damping factor that represents the proportion by which total demand is expected to decrease following a drop in frequency.

E.5.11 For each *reserve class*, an estimated GT output damping factor that represents the proportion by which GT output is expected to reduce following a drop in frequency.

E.5.12 The set of all *generating registered facilities* likely to decrease generation output as a result of a drop in system frequency.

E.5.13 The specified nominal system frequency in Hz.

E.6 <u>VIOLATION COSTS</u>

E.6.1 The values of all *constraint violation costs* pertaining to *security constraints*, *generation fixing constraints* and other *generic constraints*, as well as to *reserve, regulation* and *dispatch network lines* that are established by the *ETU* in accordance with Section 2.3 of this Chapter 4.

E.7 <u>GENERAL INFORMATION</u>

E.7.1 Notwithstanding any other provisions of this Appendix, the *market participants* shall advise the *ETU* of any circumstances relating to one or more *registered facilities*, or to the *electricity system* as a whole, which have caused or are likely to cause the *ETU* to do any of the following within the current *pre-dispatch horizon or short-term horizon*:

(a) Impose *security constraints, generation fixing constraints* or *generic constraints* that differ significantly from those that are normally applied;

(b) adjust any *reserve* or *regulation* parameters used as inputs to the *market clearing engine* in ways that differ significantly from the values normally applied by the *ETU* at each time of day;

(c) significantly revise its expectations of *load*, of any *energy* surplus or of any *energy*, *reserve*, or *regulation* shortfall; or

(d) impose *constraint violation costs* that differ significantly from the values normally applied by the *ETU* at each time of day.

APPENDIX *4F* – ADVISORY NOTICES

F.1 <u>INFORMATION TO BE INCLUDED</u>

F.1.1 This Appendix sets forth details of the information to be included in *advisory notices* issued by the *ETU* pursuant to Section 9.3 of this Chapter.

F.1.2 An *energy* surplus *advisory notice* shall indicate:

F.1.2.1 The *dispatch periods* for which an *energy* surplus is expected by the *ETU*;

F.1.2.2 the amount by which the output from *generation facilities* is expected to exceed *load* for each *dispatch period* referred to section F.1.2.1; and

F.1.2.3 whether the *energy* surplus *advisory notice* applies to the *electricity system* as a whole or is localised and, if localised, the *dispatch network nodes* to which the *advisory notice* relates.

F.1.3 An *energy* shortfall *advisory notice* shall indicate:

F.1.3.1 The *dispatch periods* for which an *energy* shortfall is expected by the *ETU*;

F.1.3.2 the amount by which the output from *generation facilities* is expected to fall short of *load* for each *dispatch period* referred to section F.1.3.1; and

F.1.3.3 whether the *energy* shortage *advisory notice* applies to the *electricity system* as a whole or is localised and, if localised, the *dispatch network nodes* to which the *advisory notice* relates.

F.1.4 A *reserve* shortfall *advisory notice* shall indicate:

F.1.4.1 The *reserve classes* to which the *advisory notice* relates;

F.1.4.2 The *dispatch periods* for which a *reserve* shortfall in respect of each affected *reserve class* referred to in section F.1.4.1 is expected by the *ETU*; and

F.1.4.3 the amount by which the required *reserve* for each affected *reserve class* referred to in section F.1.4.1 is expected to exceed the *reserve* provided for each *dispatch period* referred to section F.1.4.2.

F.1.5 A *regulation* shortfall *advisory notice* shall indicate:

F.1.5.1 The *dispatch periods* for which a *regulation* shortfall is expected by the *ETU*; and

F.1.5.2 the amount by which the required *regulation* is expected to exceed the *regulation* provided for each for each *dispatch periods* referred to section F.1.5.1.

F.1.6 A system status *advisory notice* pertaining to *load shedding* shall indicate:

Explanatory Note: Load shedding differs from energy shortfalls only; in that energy shortfalls are load shedding forecast by the dispatch algorithm, while a system status advisory notice about load shedding need not be related to the dispatch algorithm.

F.1.6.1 The *dispatch periods* for which *load shedding* is expected by the *ETU*;

F.1.6.2 the amount by which the output from *generation facilities* is expected to exceed *load* for each *dispatch period* referred to section F.1.6.1; and

F.1.6.3 whether the system status *advisory notice* applies to the *electricity system* as a whole or is localised and, if localised, the *dispatch network nodes* to which the *advisory notice* relates.

F.1.7 A system status *advisory notice* pertaining to a major equipment outage, *load* shedding or any other abnormal *ETU controlled system* conditions that the *ETU* considers material shall indicate:

F.1.7.1 The *dispatch periods* for which a major equipment outage*, load* shedding or other abnormal *ETU controlled system* condition is expected by the *ETU*; and

F.1.7.2 the nature of the major equipment outage*, load* shedding or abnormal *ETU controlled system* condition.

F.1.8 A communications warning *advisory notice*:

F.1.8.1 pertaining to an existing communications problem, shall indicate the nature and expected duration of the communication problems and provide details of any interim alternative communication methods to be used by the *ETU*, the *market participants*, as the case may be, while the *advisory notice* is in effect; and

F.1.8.2 pertaining to an anticipated communications problem, shall contain the information referred to in section F.1.8.1, an indication of time at which the communications problem is expected to commence if not avoided and the means by which the *ETU* intends to avoid the occurrence of the communications problem.

F.1.9 A price warning *advisory notice* shall indicate:

F.1.9.1 The *dispatch periods* to which the *advisory notice* relates;

F.1.9.2 the nature of the pricing problem; and

F.1.9.3 the actions proposed by the *ETU* to address the problem.

F.1.10 An pricing revision *advisory notice* shall indicate:

F.1.10.1 The *dispatch periods* to which the *advisory notice* relates;

F.1.10.2 the nature of the pricing problem; and the methodology to be used to determine settlement prices and/or quantities.

6.1 Comments on Section 4.5 – the Dispatch Rules

While not inherently "wrong" these rules are not nearly complete enough to provide real guidance to either the Dispatcher or to Market Participants. The underlying assumption of a constraint-free grid permeates this section – as it does the entire rule set – and hinders an accurate depiction of how the market is supposed to work.

There is no explicit mention of how losses are to be treated in either the dispatch process or in the final pricing. The Rules use the term "fixed losses", but in actuality, losses vary according to the level of production. We do not know whether the Market Clearing Engine relies on fixed loss factors or whether it is based on variable factors. Importantly we do not know how losses will be priced – will the MCE price on the basis of marginal or average losses?

Likewise, the DEMR do not specify how the Market Clearing Engine is to determine the amount of reserves. There is no discussion of whether energy and reserves are co-optimized or whether reserves are simply an "add-on" to the demand forecast.

While the treatment of losses and reserves represent serious flaws, the most significant omission is that the rules provide absolutely no detail on how the Dispatcher is to accomplish re-dispatch, i.e. how will the Dispatcher dispatch out-of-merit generation to solve a transmission constraint. It is not even clear whether the Dispatcher would be allowed to re-dispatch the system.

With respect to calculating the price, the rules are similarly silent when it comes to the *fact* that every time there is a constraint there will be more than one generating unit that is marginal and hence there will be more than one System Marginal Price. A further flaw in the creation of the Uniform Ghana Electricity Price is that it is based on the short run marginal cost of generation and completely ignores the price affect that will necessarily be caused by transmission constraints. In this regard the rules are inconsistent.

In conclusion the dispatch rules are incomplete and based on an incorrect assumption. There needs to be specific rules regarding how the MCE and the pricing algorithm treat losses and reserves. But most importantly the dispatch rules need to provide guidelines for how re-dispatch will be physically accomplished and how it will be reflected in the locational/nodal prices, that is - reserve requirements must be recognized as a constraint, solved for and priced as such. The incompleteness is perhaps due to the fact that most of the rules regarding dispatch and reserves are contained in the Grid Code. While this is discussed in the next section, our recommendation is to take the relevant rules pertaining to dispatch and reserves that are currently found in the Grid Code and move them to the Wholesale Market Rules and then fill in the missing areas.

APPENDIX F: Specific Reference to Section(s) in the DEMR in respect of Power System Security and Reliability

The basis for a wholesale electricity market is reliable operation of the grid. If the system is unreliable then no matter how perfect the market rules, the market will simply not work. In this regard, "the market" has precisely the same requirement as the industry – the system must be reliable. We assume, therefore, that the Dispatcher will operate the system according to industry best practices with regard to system security and reliability. This assumption is encoded in the National Electricity Grid Code (Grid Code):

> ***Art 9.01*** *- The purpose of this Operations Sub-Code is to define the general arrangements, obligations of Grid Participants, policies, criteria and procedures need to ensure the coordinated operation of the NITS in a manner consistent with the security of supply and reliability requirements as set out in Technical Schedule TS-L taking into account any expected or real constraints on the generation and transmission systems.*

Hence, our focus in reviewing the rules regarding system security and reliability is whether or not the proposed Market Design, will facilitate economic efficiency, i.e. cost savings, in achieving the current (or improved) level of reliability.

In order to operate reliably, the Dispatcher needs to have reserves – including the ability to shed load - available to manage contingencies that arise in a very short time frame, i.e. the failure of a transmission or generation facility, a sudden change in load, etc. Typically the management of such contingent events fall outside of the electricity market itself because it cannot respond within the time frame necessary to ensure reliable operation. In other words, the impetus behind ancillary services is that the electricity market through the price mechanism cannot re-allocate resources quickly enough to maintain reliability. While the term "ancillary service" is found in the DEMR, it is defined in the Grid Code.

> ***Ancillary Services***
>
> ***Art 9.98*** *- The ETU shall ensure the availability and adequacy of ancillary services to support the transmission of energy from generating resources to loads while maintaining reliable operation of the transmission system in accordance with Prudent Utility Practice.*
>
> ***Art 9.99*** *- The ETU shall operate to ensure that sufficient ancillary services are available to satisfy the performance and reliability standards of the Grid Code.*
>
> ***Art 9.100*** *- The requirements for ancillary services shall be adjusted from time to time by the ETU to take into account factors including variations in power system conditions, real-time dispatch constraints, contingency events, the prevailing risk or vulnerability level of the NITS and the results of assessments of voltage and dynamic stability.*

> ***Art 9.101*** *– The ETU shall determine the ancillary services requirements of the NITS using demand forecasts for the timeframe for which the ancillary services are to be provided.*
>
> ***Art 9.102*** *– Ancillary services shall include*
>
> ***(a)*** *Spinning Reserves,*
> ***(b)*** *Non-spinning Reserves,*
> ***(c)*** *Voltage and reactive power control and*
> ***(d)*** *Black Start Capability*

The DEMR provide for the Dispatcher to acquire spinning and “standing reserves” through Rules 4.1.20 – 4.1.22.

Procurement and Dispatch of Reserves and Regulation in the WEM

Spinning Reserves (Regulation) Procurement

Rule 4.1.20 Twenty percent (20%) of the operating capacity of each dispatchable generation registered facility will be allocated to spinning reserve.

Procurement of Standing Reserves

Rule 4.1.21 Standing Reserve is to provide standing reserves to the relevant real time market by a generation registered facility at its market network node in a dispatch period

Rule 4.1.22 Standing Reserves shall be procured based on:

(d) availability during each dispatch period;

(e) cost; and

(f) response time.

We note that forcing each generation facility to allocate 20% of their operating capacity for spinning reserve is a substantial reserve margin and above any standard as applied in North America. Certainly having 20% of the available capacity “held back” will provide the Dispatcher with a substantial margin to manage contingencies.

The Grid Code actually provides a much clearer and definitive description of reserves, starting with the

> ***Types of Reserves***
>
> ***Art 9.20*** *– <u>Operating Reserves</u> are that generation capability above firm system demand that are required to meet the standards of an adequately responsive system for regulation, load forecasting error, mismatch between generation and demand, equipment forced outages and scheduled outages. Operating reserves consist of spinning reserves and non-spinning reserves.*

> ***Art 9.21*** *– Spinning Reserves consist of the unloaded generation capacity, which is synchronized and ready to automatically serve additional demand without human intervention in order to arrest a drop of system frequency due to an instantaneous mismatch between generation and demand. It shall include and consist primarily of the additional output from currently operating generating plant that is realizable in real time and can be provided steadily for at least one hour.*
>
> ***Art 9.22*** *– A Non-Spinning Reserve is that generation capability not operating or synchronized to the system but which is available to serve demand within thirty minutes of being requested so to do. Specifically, a Non-spinning reserve shall comprise the steady output available from a generating unit that can be synchronized to the NITS and loaded up within the specified period to respond to an unexpected demand increase or loss of generation or transmission capacity.*

It is not clear whether it was an oversight or a mistake that the DEMR did not retain this language, i.e. the use of the term "Operating Reserves" which contains both Spinning and Non-Spinning Reserves, but it leads to confusion. Moreover, the Grid Code does not make use of the term "standing reserve as do with the DEMR. As a result it is not clear whether the 20% requirement in Rule 4.1.20 is meant to include the amount to be used for spin and non-spin or just the former.

The Grid Code defines the reasons why the Dispatcher can deploy spinning reserves, i.e. the uses of spinning reserves, and they appear to be much broader than the simple regulation or frequency-keeping implied by Art9.21 above. In particular, Art9.24 below plainly states that Spinning Reserve is to be used as standby or synchronized reserve:

> ***Art 9.24*** *– The Spinning Reserve at any time shall be large enough to enable the grid withstand any one of the following events:*
>
> ***(d)*** *the loss of the generating unit currently producing the highest amount of power within the NITS, or*
> ***(e)*** *the loss of generation capacity that could result from any single transmission equipment failure, fault or other contingency, or*
> ***(f)*** *the loss of any power in-feed from an interconnected system, whichever is the largest.*
>
> ***Art 9.25*** *– The ETU shall allocate and distribute the required Spinning Reserves among the generating units operating within the NITS such that the grid is able to withstand any single contingency.*

How the ETU reconciles the apparent inconsistency between Art9.21 and Art9.24 is important to how the market will operate. However we note that the DEMR could possibly be interpreted as assuming the narrow definition of spinning reserves. In particular the heading for Rules 4.1.20 – 4.1.22 is Spinning Reserves (Regulation) Procurement.

If the Dispatcher adheres to the Grid Code, then they cannot use Spinning Reserves to provide voltage and reactive support. Voltage support is usually provided by reducing MW output and increasing MVAR output. Reduced MW output is replaced through a re-dispatch of the system. This does not usually occur within a timeframe small enough to require reserve activation. Instead according to the Grid Code the ETU is required to procure reactive support separate from procuring spinning and non-spinning reserves:

> ***Voltage Management***
>
> ***Art 9.11*** *– The ETU, in operating the transmission system, shall schedule generating plant reactive power outputs and procure reactive compensation as necessary to maintain the voltages at all NITS nodes and substations within established limits, as stipulated in Technical Schedule TS-L.*
>
> ***Art 9.12*** *– Each generating plant shall be capable of continuous operation within the stipulated power factor range to support voltages under normal and contingency conditions.*

Perhaps, standing reserves are to be used for reactive support but the rules provide no insight into precisely what standing reserves are to be used for and as previously noted the Grid Code has no such term as “standing reserves”. Assuming that standing reserve is not a synonym for reactive support, the market rules provide no mechanism for the procurement or even the inclusion of reactive support in the scheduling and dispatch process.

At this point it is useful to step back and provide an overview of how the dispatch process should work:

1. Generator capacity can either be used to produce energy or withheld and used to potentially provide an ancillary service.
2. By definition, therefore, the provision of energy and ancillary services are interdependent. The more energy a generating facility provides, the less capacity they have available to provide ancillary services.
3. This interdependency will be respected in the scheduling and dispatch process.
4. Currently neither the DEMR nor the Grid Code provide any specific detail into how the interdependency between energy and ancillary services is handled particularly within the Market Clearing Engine.
    a. For example, one mechanism would be to co-optimize the provision of AS and energy in the Market Clearing Engine.
5. With regard to the price signal, there must be transparent and specific rules regarding the deployment of various ancillary service products.
    a. Must avoid the situation where the energy used to keep the system from collapsing is priced less than the energy used to manage, say, frequency.
    b. For example, economically, there is a significant difference in the value created by generation capacity that is being used as standby/synchronized reserve and gets called as a result of the

occurrence of a large contingency event as compared to the capacity that is being used to manage frequency.

   c. Moreover, when the system has had a contingent event, the price of deploying the requisite ancillary service should be higher than the price of energy.
      i. It is difficult for a market to make sense out of a situation where the system is stressed and close to collapse, yet the price is low or declining.

6. The rules are silent as to whether Ancillary Services can be deployed for longer time periods than the 30-minute market interval.
   a. For example, if per Art9.24 a contingency occurs and spinning reserve is used to balance supply and demand, it remains unanswered whether that contingency will be included in the next run of the Market Clearing Engine thereby allowing the price mechanism in the energy market to "solve" the situation or whether the spinning reserves will continue to be deployed over any number of 30-minute market intervals until the contingency event is solved.

In summary, with respect to Ancillary Services, there appear to be inconsistencies within both the Grid Code and the DEMR as well as between the Grid Code and the DEMR. In its current state, the proposed structure is unlikely to reduce the costs of reliability and given the lack of specificity/precision regarding the deployment of ancillary services it is likely to introduce uncertainty and hence higher prices into the energy market itself.

APPENDIX G: Specific Discussions in respect of the relationship of DEMR to Financial Market Outcomes, Reserve Capacity Rules and Contract Administration

Relationship of DEMR to Financial Market Outcomes

There really is no "financial electricity market" in Ghana or West Africa at the present time. In this context we mean an actively traded exchange contract similar to what you would find in North America, Australia or in the countries covered by Nordpool. The development of a competitive wholesale market in Ghana based on locational market pricing is a good first step. As the West Africa Power Pool develops their wholesale market rules and assuming Ghana integrates into the wider regional market there is the potential for a financial market to develop. The single most important requirement necessary for the evolutionary development of a robust financial market is the implementation of a non-discriminatory and transparent dispatch process. Assuming this takes place, a liquid financial market will serve to improve price discovery, increase liquidity, and improve the allocation of risk.

The market design underlying the DEMR is physical in that it deals only with the physical or actual flow/consumption of power. In comparison, some markets in North America and elsewhere, include a Day Ahead market that, by definition is a financial forward market (i.e. power is not actually produced the day before), albeit a very short term forward market. The existence of the Day Ahead market in combination with rules that allow speculative bids/offers means that non-physical participants, i.e. participants that do not own or operate generation plants or consume power, can participate in the market. Likewise, the DEMR do not include envision returning constraint rentals through a financial instrument like a Financial Transmission Right. As mentioned above, not including a Day Ahead Market or Financial Transmission Rights does not necessarily imply the market is designed incorrectly, but it does mean that the market is a physical market which, by definition, excludes financial participants.

Reserve Capacity Rules

While reserve capacity rules fall largely within the purview of the National Electricity Code and were discussed in Section 7 above we would like to highlight that the use of reserve capacity by the Dispatcher can have a substantial effect on the market price and result in not only an incorrect and inefficient price signal but necessarily lost revenues to generation facilities. As such we recommend that the rules governing how and when reserve capacity is deployed into energy are clearly defined and that actions of the Market Operator in using reserve capacity to maintain reliability are transparent.

Contract Administration

Since "bilateral electricity" cannot be distinguished from "spot electricity", i.e. the electricity bought under either a bilateral contract or through the spot market, good market design requires that the dispatch processes – and therefore, the associated rules – are indifferent to the financial arrangements under which the electricity is being transacted. The original market implemented in California is an example where the market designers mandated spot market participation and this was one of two primary reasons why the market failed.[48] This mandate, in combination with low rainfall, caused excessive and non-commercially rational exposure to high and volatile spot prices.

The traditional bilateral contract transacted in LMP-based market is a "swap" or a Contract-for-Difference (CfD). A CfD is purely financial, i.e. the contract does not specify physical supply from a specific generator to a specific load. A buyer and a seller will simply bilaterally agree on a contract price and a location and the resulting contract will be settled against the LMP at that location. Obviously for a CfD to be appropriate there must be a spot price, i.e. a nodal price, for that location and this is one of the significant derivative benefits of implementing a nodal dispatch process.

Whether or not the DEMR creates artificial incentives to purchase electricity under bilateral contracts or through the spot market depends on how the constraints are actually managed and priced, in particular how a single marginal prices is chosen from among many candidates.

Where nodal-based markets have been implemented, contract administration has become easier. If the bilateral parties want, the volumes can be scheduled through the market with the result that billing is largely done through the market and there is a central clearing house for credit risk and compliance.

With respect to existing contracts that VRA may have with customers, the DEMR should allow the financial terms of those contracts to be honored. However, to the extent that the contracts identify a specific generating facility as the supplier or a specific power factor at a given delivery point, those decisions will now be made by the Market Operator and not VRA.

[48] The other fundamental reason was that they chose a zonal, rather than nodal based, market design.

APPENDIX H: Specific Reference to Section(s) in the DEMR in respect of Market Settlements

Wholesale Market Metering

The Market Rules define metering requirements as below:

SECTION 5.2- SETTLEMENT DATA
Responsibilities

Rule 5.2.03 The *ETU* shall establish procedures for metering and collection of metering data and shall rely on the metering data collected in accordance with this Chapter and Appendix 5B for determining *settlement amounts* and, notwithstanding the provisions on liability and indemnification in Chapter one:

(a) the *ETU* shall not be required to inform any person of the receipt or use of such metering data or corrected metering data other than in the ordinary course of determining and reporting *settlement amounts*;

(b) the *ETU* shall not be liable to any person in respect of the use of such metering data or corrected metering data where effected in accordance with this Chapter.

Rule 5.2.04 Where the ETU relies on metering data provided by a market participant, *the entity* submitting such metering data shall indemnify and hold harmless the *ETU* in respect of any and all claims, losses, costs, liabilities, obligations, actions, judgments, suits, expenses, disbursements and damages incurred, suffered, sustained or required to be paid, directly or indirectly, by, or sought to be imposed upon, the *ETU* arising from the use of such metering data where effected in accordance with this Chapter.

In various other sections of the Rules, nodal metering is specified as *revenue quality metering* as governed by the Code. This is in accordance with commonly accepted metering requirements and practices for utilities.

Market Settlement

SECTION 5.1 – INTRODUCTORY RULES

Overall: OK, consists of a very general introduction.

SECTION 5.2 – SETTLEMENT DATA

Overall: Consists of very general rules and definitions regarding settlement data. The specific data elements refer back to “DEFINITIONS AND ACRONYMS”.

Specific Comments:

- **Rule 5.2.06:**

- *Reserve provider group* is defined as "a group of *reserve providers* that have similar effectiveness characteristics". Is this the same as reserve type or class? I.e., 10-minute reserve, 30-minute reserve, synchronized (spinning) reserve, non-synchronized reserve. If I understand this correctly, a specific *reserve provider group* could consist of only 10-minute synchronized reserve providers. As noted earlier under Dispatch, this is a basic underlying market design issue that needs to be addressed.
- I note that settlement intervals are hourly. This is in accordance with most ISOs/RTOs today. However, the closer the settlement interval matches the dispatch interval, the more accurate the settlement. For example, NYISO calculates prices and computes settlements to match each dispatch interval, nominally 5-minutes. PJM, Midwest ISO and ISO-NE calculate prices at a dispatch interval level, but calculate settlements on an hourly basis based on hourly average prices. These prices may be a straight average or load-weighted average; weighted average produces a more accurate hourly price. Although settlement at the interval level produces the most accurate results, the method used is ultimately dependent on degree of acceptable accuracy vs. complexity and ultimate market acceptance.

- **Bilateral Contract Data:** These Market Rules address the creation of a new, spot energy market. Bilaterals are, by definition, settled outside the spot market by parties under rules agreed upon under separate contracts. Therefore, the quantity of energy involved in bilaterals must be accounted for before settling the spot market. If, and when, a market that recognizes congestion is established, bilaterals would be subject to resulting congestion charges.

SECTION 5.3 – NET SETTLEMENT INTERVAL CREDITS

- **Net Energy Settlement Credits:**
  - Energy settlement is essentially Price multiplied by Quantity. Price has been defined as an hourly price, but it is not clear whether this is a straight or weighted average (see comments under Rule 5.2.06), Quantity has not been clearly defined. Depending on the final market rules, settlements could be based on scheduled output, actual output or some combination based on resource status and performance. For example, quantity may mean something different for a resource providing regulation vs. a resource operating to a fixed schedule.
  - Does MEP equal UGEP or does MEP reflect congestion and losses with respect to the GHUB? MEP is not defined in the Singapore Rules, since congestion does not exist and the concept of a locational price is moot. If MEP includes congestion and losses the equations for the energy credit and load debit will not balance and residuals will result.
- **Net Regulation Settlement Credits:**

  - Regulation settlement is essentially Price multiplied by Quantity. Actual performance of the resource is not accounted for.
  - According to the equation, FEQ is dependent on energy injection in addition to withdrawal. Only resources that cause a regulation burden should be subject to charges.
  - Regulation in a well designed market would be offered into the market as a product, like Energy, with a final Marginal Clearing Price (MCP). Resources providing regulation would be settled based on cleared MCPs, adjusted for actual performance. Actual settlement rules will be dependent on the final market design.
- **Net Reserve Settlement Credits:**
  - Reserve settlement is essentially Price multiplied by Quantity. Actual performance of the resource is not accounted for. "GRQ" and "LRQ" are not defined, but I assume they are generation and demand response quantities.
- Reserve in a well designed market would be offered into the market as a product, like Energy, with a final Marginal Clearing Price (MCP). Resources providing reserve would be settled based on cleared MCPs, adjusted for actual performance. Actual settlement rules will be dependent on the final market design.
- **Settlement Interval Energy Uplift Charges**
  - This appears to be a simple summation of imbalances over all products, plus a meter error adjustment.
  - A properly designed settlement system should identify sources of imbalance and give the users the ability to minimize them. A designed based on marginal pricing that reflects congestion is transparent and reduces uplift. A design such as this gives the user the ability to see true costs and take actions to hedge against them and minimize costs. Uplift cannot be hedged.
  - Since congestion and losses are not accounted for in the energy settlement, energy imbalance components of uplift are likely to be excessive. The cost of energy should be transparent and expressed in a locational price, not buried in uplift.
- **Net Settlement Interval Credits**
  - NPSC is a summation of NASC (a typo?); which is workable and acceptable.

SECTION 5.4 – RECOVERY OF NON-SETTLEMENT-INTERVAL COSTS

- **The Monthly Energy Uplift Charge**
  - Recovers all other charges/credits not captured by energy, ancillary services and imbalance settlements, including;
    - Cost based ancillary services, such as voltage support and black start services. How are these costs verified?;

        - Costs incurred from testing of resources to be used in supplying ancillary services;
        - Costs arising from disputes and arbitration;
        - Charges and credits from penalties and awards;
        - Costs attributed to grandfathered agreements;
        - Miscellaneous costs; and
        - Any prior period adjustments.
- **Self-Generation**
    - This section defines self-generation facilities and includes registration and settlement for imbalance energy. Settlement seems to be in line with previously defined settlement rules.
- ***MOP* Administrative Costs and Associated Fees**
    - These are commonly known as "Scheduling, System Control and Dispatch" costs, and can be considered as a cost based ancillary service.

Credit Support Requirements

Purpose and general market participant obligation (Rules 2.7.01 – 2.7.02)

These rules serve as a general introduction to this Section. It states that credit support must be provided and maintained and obligations met, according to the rules in this section, for participation in the **real-time markets** (emphasis added).

Current exposure and estimated net exposure (Rules 2.7.03 – 2.7.04)

Credit exposure and estimated net exposure of a market participant are determined by procedures specified in the *market manual*.

Rule 1.8.01 specifies that one or more *market manuals* may be established:**"Rule 1.8.01** The *ETU* may establish one or more *market manuals* in accordance with the procedures set forth in this market rules." However, this section does not specify a specific *market manual*.

Estimated average daily exposure and credit support value (Rules 2.7.05 – 2.7.10)

Estimated average daily exposure must be provided to the ETU. However, this exposure is defined by an again unspecified *market manual.* Credit support equal to 30 days exposure must be provided. This appears to be adequate, assuming a 30 day settlement cycle. The ETU is responsible for reviewing and revising credit support requirements and informing market participants as revisions become necessary. Revised credit support must be provided within 5 business days of when a revision becomes effective.

Other than the reference to an unspecified manual, these rules are similar to rules effective in other markets.

Margin calls (Rules 2.1.11 – 2.7.12)

Market participants are notified when estimated net exposure reaches 60% of the participant's credit support and a margin call is made at 70%. This rule is similar to rules effective in other markets.

Margin call requirements (Rules 2.7.13 – 2.7.14)

Margin calls may be satisfied by replenishing credit support as specified within the Rules or by paying a specified portion of the owed obligation. Margin calls must be met by the close of the second business day after the margin call. This rule is similar to rules effective in other markets.

Obligation to provide credit support (Rules 2.7.15 – 2.7.23)

These sections define the market participants' obligation to provide and maintain credit support. Requirements can be met through letters of credit, cash deposits or Ghana Government Treasury bills. These requirements are further defined in Rules 2.7.18 through 2.7.21. Again, references are made to an unspecified *market manual*. Terms of notification and replacement in the event of expiration of credit support are defined.

Exercise of rights to credit support (Rules 2.7.24 – 2.7.32)

These rules define the rights of ETU to draw on credit support in the event of a default. In addition to the defaulted amount, any addition expenses, charges or fees resulting from the default may also be recovered. These rules are similar to rules effective in other markets.

Return of credit support (Rules 2.7.33 – 2.7.35)

These rules specify return of credit support in the event of a requirement reduction, termination or withdrawal from the market and are similar to rules effective in other markets.

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6562 Hallissey Court
Centreville, Virginia 20120-1062
United States of America

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