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SUBJECT	:	**MANAGEMENT OF TRANSMISSION CONGESTION**
FOR	:	**CONSULTATION**
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Executive Summary

EMC received a proposal suggesting to 1) identify the presence of transmission constraints ex-ante and 2) compensate generation units that are given “must run” obligations due to congestion causes. This paper examines the extent of transmission constraints in Singapore, and holistically examines the proposal’s suggestions and other congestion management initiatives.

In Singapore’s context, there are usually adequate transmission resources to serve all generating units, barring ad-hoc transmission maintenance or outage cases. However, there could be transmission tightness in the Southwest block going forward, whereby a surge in new generation plantings may lead to a surplus of generation capacity and corresponding transmission constraints. This expected congestion should be relived with the upcoming 400kV substation with a connecting undersea cable tunnel linking Jurong Island and mainland, tentatively scheduled for completion in 2017/2018.

The paper analyses congestion management along the following key strategies:

i) **Infrastructure Building** – Building new transmission lines may be the most straightforward but building a system to handle all congestion may not be economical.

ii) **Anticipating and Avoiding Congestion** – The forecast MNN prices are sufficient in providing adequate and complete information in engendering the right market response from the industry in managing transmission congestion. It is thus not necessary to publish the presence of transmission constraints ex-ante as proposed.

iii) **Commercial Redispatch** – This relates to the proposal that generation units given “must run” obligations should be compensated. In general, market solutions based on locational marginal prices are most efficient, unless there are

legitimate concerns over local market power. Even then, such units should seek compensation directly from EMA. If the EMA agrees with such an approach, then with minor amendments to the current provisions in the market rules, EMC can make payment for compensation approved by EMA to such gencos. These payment costs will then be recovered from loads via the MEUC.

The paper also examines FTRs and concludes that they are inappropriate in managing the specific nature of transmission congestion in Singapore's context. This is because they are financial hedging tools that do not address the root cause of transmission congestion and, given that foreseeable network constraint issues are expected to be alleviated tentatively by 2017/2018, their implementation costs are unlikely to be justifiable.

During the 62nd RCP meeting on 10 July 2012, the panel supported the paper's proposal that:

- There is no need to identify transmission constraints ex-ante, as the effect of congestion should be reflected in the forecast nodal prices;
- if must-run obligations are imposed onto any genco for locational market power, then the genco should be compensated such that its costs of running generation potentially more expensive than their locational marginal price are made whole; and
- there is no value in considering Financial Transmission Rights at this juncture.

The panel further requested that regular updates on transmission developments and potential constraints be provided by EMA and SPPA to the industry, so as to allow investors to make informed decisions in their investments.

1. Introduction

Transmission congestion occurs when there is insufficient transmission capacity to simultaneously accommodate all requests for transmission service within a region. With the advent of deregulation and policies of open access, allocation of scarce transmission resources has become a key factor for the efficient operation of electricity markets, system reliability and control of market power[1].

EMC received a proposal suggesting to 1) identify the presence of transmission constraints ex-ante and 2) compensate generation units that are given “must run” obligations due to congestion causes. This paper examines the extent of transmission constraints in Singapore, and holistically examines the proposal’s suggestions and other congestion management initiatives.

2. Background

Singapore’s transmission network is relatively congestion-free, although low congestion does not imply zero congestion. Under the principle of Open Access in the Transmission Code, Singapore Power PowerAssets (SPPA) is required only to cater for 100% of a generating unit’s export capacity from the unit’s switchhouse to SPPA’s connecting substation under normal conditions. There are no capacity obligations beyond SPPA’s substation, whereby the generating unit will have to compete with other units for network resources[2].

The last episode of significant transmission congestion occurred in January 2008, when congestion between the northern and southern nodes of the network led to nodal price differences of as high as $3000/MWh. When SPPA subsequently upgraded the capacity for Line 230 Ayer Rajah to CCK, from 250MVA to 500MVA, these price separation episodes were eliminated. Since then, there are usually adequate transmission resources to serve all generating units, barring ad-hoc transmission maintenance or outage cases.

However, there could be a possibility of transmission tightness in the Southwest block going forward, whereby a surge in new generation plantings may lead to a surplus of generation capacity and corresponding transmission constraints. EMA has carried out studies to model the likely extent of the transmission constraints. Based on 4x400MW of new generation plantings and projections of electricity demand in the Jurong Island segment of the SW transmission network in 2014, and assuming that 97% of installed generation capacity in the SW transmission network is being offered into the electricity market for injection into the grid, EMA estimates that the percentage export capacities at key constraints to be between 90-91% under normal operating conditions[3].

Singapore Power PowerGrid (SPPG) has already planned to develop a new 400kV substation with a connecting undersea cable tunnel linking Jurong Island and mainland to improve export capacity. This connection is tentatively scheduled for completion in 2017/2018, and the EMA does not foresee any further network constraint issues in Jurong Island beyond that[4]. However, with the open access principle, there is no guarantee that the network will always remain constraint free.

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[1] Congestion Management Requirements, Methods and Performance Indices, B.J. Kirby, J.W. Van Dyke, Oak Ridge National Laboratory, June 2002.
[2] Developments in the Singapore Electricity Transmission Network, Energy Market Authority, 05 Apr 2011.
[3] Developments in the Singapore Electricity Transmission Network, Energy Market Authority, 05 Apr 2011.
[4] Developments in the Singapore Electricity Transmission Network, Energy Market Authority, 05 Apr 2011.

It thus appears that Singapore's transmission constraints are largely occasional. And with plans to bolster transmission in the Southwest block already underway, even the expected structural congestion in that region is temporal in nature.

3. Approaches to Transmission Congestion Management

Different types of congestion have different drivers, duration, persistence, impacts, etc. which may in turn require different solutions. Some forms of congestion could be viewed as a reliability problem to be addressed through additional investment. However, congestion, like peak period power prices, can sometimes be an economic signal that can and should be addressed through individual market actions[5]. There are 5 broad approaches to manage congestion[6]:

i) **Infrastructure Building** – construct sufficient new facilities so that congestion rarely occurs and curtailments are necessary only when there are extraordinary events. However, this is expensive, and building a system to handle all congestion would be vastly uneconomical, because congestion does not occur most of the time.

ii) **Anticipating and Avoiding Congestion** – use procedures/tools to predict congestion, and correspondingly adjust projected generation dispatch patterns to minimize congestion

iii) **Commercial Redispatch** - Transmission provider/system operator relieves congestion by directing generator upstream of congestion to "turn off", and generator downstream to "turn on". Upstream generator will receive energy payments based on original schedule less cost savings from not operating. Downstream generator will be paid based on the generator's incremental cost of producing power plus a profit margin. In addition, there may be a capacity cost associated with the option to call on a generator to provide redispatch.

iv) **Non-Wires Solutions (NWS)** – NWS are demand-side or power management practices that would defer or eliminate the need to pursue a transmission hardware improvement. This could include implementing controlled voluntary/contractually-agreed-to load curtailment in affected areas.

v) **Load Curtailment** – This approach recognizes congestion will happen and that curtailments will be necessary. Dispatchers would need advanced tools such as curtailment calculators and other flowgate-specific tools to enhance their ability to deal with network problems.

Each approach has its own tradeoffs (e.g. complexity, cost). Thus, a robust congestion management strategy is likely to employ a variety of these approaches depending on the nature of congestion.

[5] Transmission System Congestion Relief, British Columbia Utilities Commission: Staff Discussion Paper
[6] Protecting and managing an increasingly congested transmission system, White Paper by Bonneville Power Administration, April 2006

4. Application to Singapore's Context

This section applies the congestion management framework discussed in section 3 to examine what is already done and/or what more can be done in Singapore's context.

i) Infrastructure Building

Singapore's transmission grid is already quite congestion-free, given our significant investments in transmission assets. And while building new transmission lines may appear the most straightforward solution to transmission congestion, it may not be the most economical. This could occur if an expensive transmission line is built to relieve congestion that occurs only intermittently and/or becomes less utilised when power flow changes over time.

An ideal congestion management system should thus allow competitive forces to efficiently determine which transactions should be reduced to avoid congestion. Aided by information transparency from relevant authorities, investors should factor the financial impact of potential localised transmission congestion in their investment decisions[7].

ii) Anticipating and Avoiding Congestion

SWEM employs locational marginal pricing, which reflects the pricing of a marginal unit of electricity at a given node. This nodal price thus incorporates the possible effects of transmission congestion and losses associated with the given node.

As SWEM operates on the principle of self-commitment, neither EMC nor PSO unilaterally adjusts generation dispatch patterns to minimize congestion. Rather, in the forecast schedules (e.g. Short-Term Schedule, STS), the Market Network Node (MNN) forecast prices for individual nodes in the upcoming periods are published. If transmission congestion exists, MNN prices of nodes downstream of the congestion will be higher, which incentives corresponding gencos to increase their supply and/or run up their units to relieve the congestion.

The proposal received suggests that "*The existence of transmission constraints, if present, is usually made known only ex post when price separation occurs. This situation is not ideal as the presence of such constraints should have been made known in advance.*" However, it may not be helpful to publish the existence of transmission constraints for the following reasons:

- Transmission constraint information without corresponding power flow data is inadequate (e.g. the genco would not know whether a node is upstream or downstream of the congestion)
- For a genco situated a distance from the congestion, it would not know if increasing its supply would aggravate or alleviate the congestion, given the complexities of power flow

As such, forecast MNN prices in themselves should provide adequate and complete information in engendering the right market response from the industry in managing transmission congestion.

[7] Congestion Management Requirements, Methods and Performance Indices, B.J. Kirby, J.W. Van Dyke, Oak Ridge National Laboratory, June 2002.

iii) Commercial Redispatch

In the context of SWEM's locational marginal pricing, the strategy of directing generators upstream/downstream of congestion to turn off/on interferes with the market schedules and should be avoided as it leads to productive inefficiencies (i.e. not using least-cost schedule to meet system demand). This is also the prevailing sentiment in other markets such as ERCOT, whereby "reliability-must-run and out-of-merit order generation is used for congestion management only in the absence of market-based solutions, but they are available if the ISO believes they are needed." [8]

The proposal received stated that:

> *Where a constraint is present and certain generation units have to bid in order to be dispatched to maintain system stability, these units should be compensated as "must run" units as is done in other markets. Running these units avoids price separation incidents and ensures that system reliability is not compromised; it is thus reasonable that these units are compensated.*
>
> *Such market solutions are preferred to than non-market measures which fail to signal any existing constraint and thus place the burden of maintaining system stability solely on gencos. It is proposed that the RCP verify the presence of such constraints and evaluate the types of "must run" payment schemes that can be put in place to ensure that units called on to run are adequately and fairly compensated.*

Market solutions based on locational marginal prices are most efficient....

Essentially, locational marginal prices provide valuable price signals to guide corresponding investment. It is thus counter-productive to artificially mute them by imposing must-run requirements, if any. A study suggests that "the owner is simply earning a temporary locational rent by virtue of its favorable location on the grid. This locational rent will tend to attract local entry until the rent is eliminated. Thus, allowing the generator to earn this rent promotes efficiency, while attempting to transfer this rent to consumers through regulation is likely to be administratively burdensome and introduce inefficiencies." [9]

This view is echoed in another report, which states that "a uniform payment to all generators across PJM, regardless of location, would provide the wrong incentives – either too high or too low – to resources at each location…The challenges is whether market-based prices in those wholesale markets can provide the right incentives to support investments in the appropriate amount and types of electricity supply and demand-side resources."[10]

Both quotes above reinforce the principle that locational prices are required to provide the correct incentives to guide the planting of generators, the absence of which would be the congregation of generation plants in geographical areas that aggravate, rather than alleviate transmission congestion.

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[8] Congestion Management Requirements, Methods and Performance Indices, B.J. Kirby, J.W. Van Dyke, Oak Ridge National Laboratory, June 2002.
[9] Must-Run Generation: Can We Mix Regulation and Competition Successfully, Jurewitz and Walther, The Electricity Journal, Dec 1997.
[10] PJM's Reliability Pricing Mechanism: (Why It's Needed and How It Works), Andrew Ott, Vice President (Markets), March 2008

...unless there are legitimate concerns over local market power...

Perhaps the only justification for must-run requirements is from the angle of market power mitigation. For example, local generation is needed to serve customers where transmission constraints limit imports, or to maintain system stability. Whenever local generation is needed for reliability, the challenge is to secure its performance while controlling its potential market power. Local reliability and local market power are just two sides of the same coin - it is precisely because a generator is sometimes needed to operate that it has a potential for local market power.[11]

...even then, units with 'must run' obligations should be compensated.

EMC agrees that if such must-run requirements are imposed onto any genco, then they should be compensated such that their costs of running potentially more expensive generation are made whole. Indeed, instead of rewarding these units for their crucial role in serving local demand and/or maintaining system security, it would be perverse to penalize them by slapping on them must-run obligations without the possibility of make-whole payments.

As is, there are already provisions in the Market Rules to make payment for such must-run requirements:

a) Where the 'must run' obligation pertains to <u>local market power</u>, Gencos could be paid under Chapter 7, Section 4.1.3 (with minor amendments). This section states that:

   Prior to the beginning of each calendar month, *EMC* shall calculate the monthly *transitional payment* amount (MTRA), as directed and in the manner specified by the *Authority*

   MTRA= *transitional payments* (in dollars) for a calendar month

   Transitional payments are a number of arrangements approved by the EMA for licensees in operation before market start, which allow these parties to continue under similar arrangements into the future. It is thus plausible and consistent in principle to pay Gencos using this mechanism, with a minor rule change to remove the requirement that the arrangement must exist before market start.

   In this case, such units should seek compensation directly from EMA. If the EMA agrees with such an approach, then with this minor rule change, EMC can make payment for compensation approved by EMA to such gencos. These payment costs will then be recovered from loads via the MEUC.

b) Where the 'must run' obligation pertains to <u>system reliability</u>, Gencos could be awarded Reliability Must-Run Service contracts, as described in Chapter 5, Section 8.5.

   Gencos could recover the costs (including the direct costs and opportunity costs of actually providing the contracted service when directed by the PSO) under Chapter 5, Section 8.6.1.

[11] Must-Run Generation: Can We Mix Regulation and Competition Successfully, Jurewitz and Walther, The Electricity Journal, Dec 1997.

In either cases, EMC will recover the payments from the market using the Monthly Energy Uplift Charge (MEUC) from loads based on their withdrawal quantities.

iv) Non-Wires Solutions (NWS)

NWS refer to demand-side or power management practices whereby load is reduced in response to transmission congestion (or high prices in general), which defers or eliminates the need for transmission upgrades. EMA is currently already studying the feasibility of various Demand Response initiatives[12], and the industry will be consulted in due time.

v) Load Curtailment

This approach accepts that load curtailment is inevitable arising from transmission congestion, and suggests advanced tools to minimise the impact of these network problems. As Singapore is nowhere near (nor should we ever get there) this dire level of transmission congestion, this paper does not discuss this strategy any further.

5. Clarification on Financial Transmission Rights

This paper wraps up the discussion on transmission congestion by addressing some misconceptions on Financial Transmission Rights (FTR) as a congestion management tool.

Widely used in some other markets, FTRs provide the owner with income and preferential scheduling from congested interfaces. A market participant that owns FTRs equal to (same congestion path, same direction and same number of MW) a transmission schedule that the market participant is trying to execute is immune to congestion pricing because the FTRs provide income equal to the transmission congestion charge that market participant has to pay[13]. Essentially, there are 2 different FTR models:

i) **Physical Rights Model** – This FTR model only considers scheduling rights. The FTR owners schedule across inter-zonal interfaces. Any FTR that is not used in the day-ahead market will be released in the hour-ahead market for others to use without retaining the financial rights.

ii) **Financial Rights Model** – The FTR holder privileges are limited to financial rights. FTRs are not needed to schedule a transaction on the transmission system and do not provide higher-priority service when the ISO has to reduce schedule. The FTR owner receives payments based on the hourly energy LMP differences across a specific path.

The FTR regime is an inappropriate tool to manage the specific nature of transmission congestion in Singapore's context for the following reasons:

i) FTRs are just financial tools that hedge nodal price volatility arising from transmission congestion (symptom), rather than address generation and transmission investment adequacy (root cause).

[12] An update of EMA's Intelligent Energy System (IES) and Demand Response (DR) Working Groups was presented at the 58th RCP Meeting on 08 Nov 2011.

[13] Congestion Management Requirements, Methods and Performance Indices, B.J. Kirby, J.W. Van Dyke, Oak Ridge National Laboratory, June 2002.

ii) FTRs are useful if a party wants to eliminate the price risks/uncertainty, but does not eliminate the structural price differential between nodes upstream and downstream of a congestion (e.g. in the case of overcapacity in the Southwest block). This is because the party would have to purchase the FTR at a price that would commensurate with the expected structural price differential.

iii) Physical FTRs represent a contractual approach to addressing congestion, hence suffers from being inflexible (e.g. holding a FTR that grants transmission capacity for 6 months would be wasteful if there are periods within these 6 months when the genco does not generate). A more dynamic approach would be the current arrangement, whereby gencos could always bid low (or even negative) prices to increase its chances of dispatch.

iv) Implementing a FTR regime would entail significant implementation costs. Given that there are no foreseeable network constraint issues beyond 2017/2018, the costs are unlikely to justify the limited benefits.

6. Industry Consultation

The concept paper was published for consultation on 28 May 2012, and the following comments were received.

Comments from SP PowerAssets

As the new 400kV substation with a connecting undersea cable tunnel linking Jurong Island and mainland is currently pending EMA approval, we would like to clarify that the 2017/2018 completion date indicated in your paper is only tentative. We suggest that the paper be amended to reflect that the completion date of 2017/2018 is tentative.

EMC's response
The paper was revised to state that the 2017/2018 completion date is tentative.

Comments from PSO and EMC's corresponding responses

Pg 2: "... Even then, such units should seek compensation from EMA".

PSO: EMA is neither a market participant nor service provider, and is not party to any market agreement and has no contractual relationship with any market participant, which section of market rules mention Gencos can seek compensation from EMA?

EMC: EMC's proposal that Must Run Units be compensated such that they at least recover their costs is based on market design principles. We agree that EMA is not a contractual party to the market rules. Thus, generators imposed with must run requirements pertaining to local market power should seek compensation directly from the EMA. The suggested amendments to the Market Rules are to allow EMC to pay such units if EMA agrees to compensate them, and to recover the payments to such units from loads via MEUC. The paper has been amended to make this clearer.

Pg 3: "...development of a new 400kV substation with a connecting undersea cable tunnel linking Jurong Island and mainland to improve export capacity. This connection is scheduled for completion in 2017/2018, and <u>the EMA does not foresee any further network constraint issues in Jurong Island beyond that</u>".

Pg 9: '...EMA does not foresee any further congestion after this connection's scheduled completion in 2017/2018."

PSO: The portion highlighted in underline is incomplete. EMA paper 'Developments in the Singapore Electricity Transmission Network' issued on 5 April 2011 has stated that '...However, with the open access principle, there is no guarantee that the network will always remain constraint free.' This should be reflected in EMC's Consultation paper.

EMC: PSO's qualifier is noted and reflected in the paper.
PSO: Pg 4: Bullet numbering not in sequence.

EMC: Bullet numbering is updated

i) Infrastructure Building
Pg 5: "This could occur if an expensive transmission line is built to relieve congestion that occurs only intermittently and/or becomes obsolete when power flow changes over time."

PSO: Rest assure that EMA will not approve any transmission network expansion plan that would make any equipment or line 'obsolete' over time. Infrastructure has to be built ahead of demand and as it takes long lead time to implement transmission projects, any addition of transmission equipment/line is to meet future demand. Temporary reduction of loading on certain transmission equipment/line could happen as new equipment/line is being added. However, equipment/line loading will increase over time as demand increases they do not become 'obsolete'.

EMC: PSO's comments are noted and the paper is amended to reflect as such.

ii) Anticipating and Avoiding Congestion
Pg 5: 'If transmission congestion exists, MNN prices of nodes downstream of the congestion will be higher, which incentivizes corresponding gencos to increase their supply and/or run up their units to relieve the congestion.'

PSO: The converse may be true. Wouldn't it be more profitable for Gencos at downstream of the constraint to withhold supply and maintain high MNN price instead of increasing supply causing the MNN price to come down and reduce their revenue substantially?

EMC: If Gencos withheld supply to maintain high MNN prices, this constitutes an exercise of market power which will be thoroughly investigated by the MSCP and EMA.

Pg 5: 'The proposal received suggests that "The existence of transmission constraints, if present, is usually made known only ex post when price separation occurs. This situation is not ideal as the presence of such constraints should have been made known in advance'.... 'As such, forecast MNN prices in themselves should provide adequate and complete information in engendering the right market response from the industry in managing transmission congestion.'

PSO: Agree with EMC that forecasted price separation in the STS, PDS & MOS would be a good indication of transmission constraints ex-ante, if any. Rare occasions of price separation appearing only on RTS are typically due to transmission equipment/line forced outages, which in any case could not be anticipated.

EMC: PSO's comments are noted.

iii) Commercial Redispatch

Pg 6: "...Both quotes above reinforce the principle that locational prices are required to provide the correct incentives to guide the planting of generators, the absence of which would be the congregation of generation plants in geographical areas that aggravate, rather than alleviate transmission congestion".

PSO: While locational pricing may provide incentives on planting of generators, it could be argued that because of land constraints in Singapore, there is constraint on where generators could be sited. Other factors such as availability of fuel (gas) could also influence planting decision.

EMC: Agree with PSO's comments. Locational pricing is one dimension of consideration in influencing planting decision, and there are other considerations such as availability of fuel.

Pg 7:' Transitional payments are a number of arrangements approved by the EMA for licensees in operation before market start, which allow these parties to continue under similar arrangements into the future. It is thus plausible and consistent in principle to pay Gencos using this mechanism, with a minor rule change to remove the requirement that the arrangement must exist before market start. Gencos could then seek compensation directly from EMA for any must-run requirements imposed to mitigate market power, following which EMC will pay them through the MTRA mechanism.'

PSO: EMA-RD should be consulted on this.

EMC: When the consultation paper was published, all parties are welcome to submit comments, including EMA-RD.

iv) Non-Wires Solutions (NWS)

Pg 4: 'NWS are demand-side or power management practices that would defer or eliminate the need to pursue a transmission hardware improvement. This could include implementing controlled voluntary/contractually-agreed-to load curtailment in affected areas. '

PSO: Demand side or power management practices could potentially defer but not eliminate the need for addition of new transmission equipment/line to relieve congestion. Furthermore, what if there is no/insufficient volunteer from loads in the affected area? Or loads originally contracted for Demand Side Management pull out from the scheme, it would take long lead time to build transmission equipment/line to relieve the congestion. In the meantime, loads within the affected area could be subjected to prolong power rationing.

EMC: PSO's comments are noted.

Financial Transmission Rights

Pg 9: "...Implementing a FTR regime would entail significant implementation costs."

PSO: EMC may want to indicate the associated cost.

EMC: It would be not be possible to assess the cost without a detailed study and agreement on the design of FTRs involving the key stakeholders. However the cost should be in the order of millions.

Comments from Senoko Energy

Generation infrastructure investment decisions should be aided by information that would allow the potential impacts of transmission congestion to be taken into account. While the EMA's April 2011 paper is very pertinent and welcomed, information dissemination regarding systematic transmission constraints should be regular rather than ad hoc.

We support the conclusion that market solutions based on locational marginal prices are most efficient and that must-run units (MRUs) should be compensated. In this regard there needs to be a clear framework covering the basis and the responsibility for:

1. *Activation of MRUs (e.g., are MRUs pre-identified or activated dynamically as part of the market-clearing process?).*
2. *Determining the dispatch quantities of MRUs (e.g., are they constrained-on or simply need to manage to achieve a minimum dispatch via their offers?).*
3. *Determining the quantum of compensation for both direct and opportunity costs (e.g., is compensation formulaic or based on discretion?).*

EMC's response
As issues on systematic transmission constraints are under the purview of EMA and PowerAssets, the RCP can consider conveying Senoko Energy's concerns to them. With regards to the framework imposed on MRUs, the specific nature of the framework will likely be determined by EMA on a case by case basis.

Comments from Keppel Energy

We support EMC analysis and conclusions that:

- *It is not necessary to publish the presence of transmission constraints ex-ante;*
- *The generation units given "must run" obligations should seek compensation from EMA if any additional costs which are not addressed under the current market solutions of locational marginal pricing; and*
- *FTRs are financial hedging tools that do not address the root cause of transmission congestion.*

EMC's response
Keppel Energy's comments are noted.

Comments from Sembcorp Cogen

Further to your analysis in the paper, we would like EMC to review if new embedded genset should not be allowed to plant on the South-west block since congestion constraints or tightness is expected, going forward and before the completion of 400kv substation in 2017/2018. Also, to review if the Market should curtail power export from embedded gensets since their main purpose was to be self-sufficient and not sell electricity for commercial purposes.

EMC's response

As issues on embedded generation are under the purview of EMA, the RCP can consider conveying Sembcorp Cogen's concerns to them.

7. Conclusion

This paper examines the extent of transmission constraints in Singapore, and various congestion management initiatives.

There is expected to be transmission tightness in the Southwest block arising from a surge in new generation plantings. However, plans are already underway to develop a new 400kV substation with a connecting undersea cable tunnel linking Jurong Island and the mainland to improve export capacity. This connection is tentatively scheduled for completion in 2017/2018, and the EMA does not foresee any further network constraint issues in Jurong Island beyond that[14]. However, with the open access principle, there is no guarantee that the network will always remain constraint free.

This paper examines transmission management initiatives along the following 5 key strategies:

i) **Infrastructure Building –** While building new transmission lines is often the most straightforward solution, it usually comes at a significant cost. Economic forces should thus decide whether the line should be built, and/or whether gencos should be backed off to avoid congestion. Investors should thus factor the financial impact of potential localised transmission congestion in their investment decisions.

ii) **Anticipating and Avoiding Congestion** – The proposer suggests making known the existence of transmission constraints in advance. However, forecast MNN prices in themselves should be adequate in engendering the right market response to manage transmission congestion.

iii) **Commercial Redispatch** – The proposer suggests that units with "must run" obligations should be compensated. EMC assess that must run obligations should be imposed only when there are concerns of market failure. When this happens, these units should be compensated to make-whole their running costs, so as not to penalize them. As is, there are already provisions in the Market Rules to pay for such must-run requirements.

iv) **Non-Wires Solution (NWS) –** EMA is already studying the feasibility of various Demand Response initiatives, which would lead to load reduction at times of transmission congestion (or high prices in general).

v) **Load Curtailment –** Load curtailment is unlikely in Singapore's context.

The paper also examines FTRs and concludes that they are inappropriate in managing the specific nature of transmission congestion in Singapore's context. This is because they are financial hedging tools that do not address the root cause of transmission congestion and, given that foreseeable network constraint issues are tentatively expected to be alleviated by 2017/2018, their implementation costs are unlikely to be justifiable.

[14] Developments in the Singapore Electricity Transmission Network, Energy Market Authority, 05 Apr 2011.

8. Discussion at the 62nd RCP Meeting

During the 62nd RCP meeting on 10 July 2012, the panel discussed the concept paper and unanimously agreed on the following:

A) Identification of Transmission Constraints Ex-Ante

If transmission congestion exists, the forecast MNN prices should be sufficient to incentivise gencos to relieve the congestion. As such, there is no need to identify transmission constraints ex-ante.

B) Compensation for Must-Run Obligations

If must-run obligations are imposed onto any genco for locational market power, then the genco should be compensated such that its costs of running generation potentially more expensive than their locational marginal price are made whole. This ensures that such gencos are not inadvertently penalized while playing the crucial role in serving local demand and/or maintaining system security.

Ssuch gencos under must-run obligations should seek compensation from the EMA. If EMA agrees in principle to compensate these gencos, then the RCP would propose amendments to the market rules to enable EMC to pay the genco and recover the payments from load using the MEUC mechanism. The compensation amount will be determined by the EMA in relation to the nature of the specific must-run arrangement.

C) Financial Transmission Rights

FTRs do not address the root cause of transmission congestion and their significant implementation costs are unlikely to be justifiable given that foreseeable network constraint issues are expected to be alleviated tentatively by 2017/2018. Thus, there is no value in considering Financial Transmission Rights at this juncture.

D) Regular Updates of Transmission Developments

Under the principle of Open Access in the Transmission Code, there are no capacity obligations on Singapore Power PowerAssets (SPPA) beyond its substation, whereby the generating unit will have to compete with other units for network resources.

To allow investors to make informed decisions and factor the financial impact of potential localised transmission congestion in their investment decisions, the RCP requests EMA and SPPA to provide updates regarding transmission developments and potential constraints. The sharing of such information during the CEO Industry forum held on 05 April 2011 was very useful, and the RCP requests that such information be made known on a regular basis. In addition, more detailed information on transmission could be provided in EMA's annual Statement of Opportunities publication.