Energy
Market
Company

Out-of-Merit-Order Dispatch

A Market Clearing Engine
Co-Optimisation Study

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About the Author

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Lu Feiyu joined Energy Market Company, the market operator for the National Electricity Market of Singapore, as a Market Analyst in March 2002. His primary responsibilities are the daily operation of the market and review of its outcome, dissemination of market information and in-house application development. Feiyu is also one of the company’s pioneers in conducting local and international training and educational forums about the market clearing engine, specifically its formulations, pricing methodology and system enhancements. He is actively involved in enhancing the market system by identifying gaps between business processes and the market system, suggesting improvements and preparing and performing user acceptance tests. He also contributes to the market rule change process through technical reviews of the proposed changes.

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Table of Contents

1.0 Introduction

One of the market participants of the NEMS queried an unexpected dispatch pattern it observed on the previous trading day. One of its generating units was not fully dispatched although the marginal price was much more than its offered price, whereas another unit was dispatched much higher than the marginal price offer block.

An investigation was conducted shortly after the enquiry was received. This report sets out the result of the investigation and makes some recommendations to the market participants regarding such instances.

2.0 Background

The very basic market clearing mechanism is based on merit order dispatch (MOD). The market clearing engine (MCE) receives valid offers and bids for energy products from market participants, which it sorts in order of offer and bid prices. The energy is dispatched to maintain a balance between supply and demand. Some general rules apply:

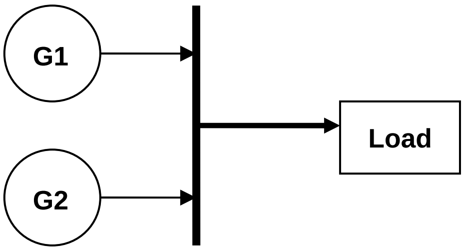
- The bids priced above the marginal price are fully dispatched.
- The bids priced below the marginal price are not dispatched at all.
- The offers priced above the marginal price are not dispatched at all.
- The offers priced below the marginal price are fully dispatched.

The market participant was puzzled when its dispatches were not in compliance with the above rules.

In an energy-only market, the rules listed above are held constantly. However, in a co-optimised market, such as the NEMS, the energy dispatch is always cleared at the same time as that of ancillary services such as reserve and regulation. This trade-off between multiple products may result in the rules being broken for the energy product.

3.0 Analysis

In order to understand the issues better, we'll start with a simple example. Suppose we have a single busbar system, with two generation units and one load connected to this busbar, as depicted below:



The load is bidding at a very high price ($50,000/MWh is used to be consistent with the NEMS design), while the two generators offer as below:

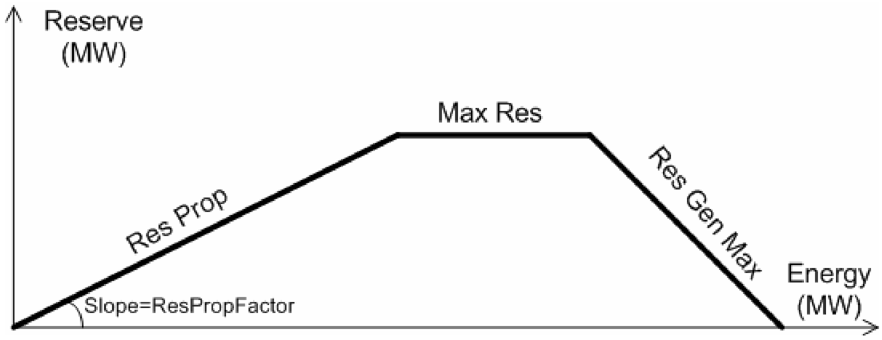
Energy	**Block 1**	**Block 2**
G1 (Cap.=100MW)	100MW $20/MWh	-
G2 (Cap.=100MW)	100MW $25/MWh	-

Reserve	**Block 1**	**Block 2**
G1 (Max=10MW; ResProp.=0.1)	10MW $2/MWh	-
G2 (Max=100MW; (ResProp.=1)	100MW $1/MWh	-

Only one class of reserve is considered in this example. A simple and well-known energy-reserve trade-off model is used, which consists of three constraints:

- reserve proportion constraint, i.e., Reserve <= Energy * ResPropFactor
- maximum reserve constraint, i.e., Reserve <= MaxRes
- reserve generation maximum constraint, i.e., Reserve <= Cap – Energy

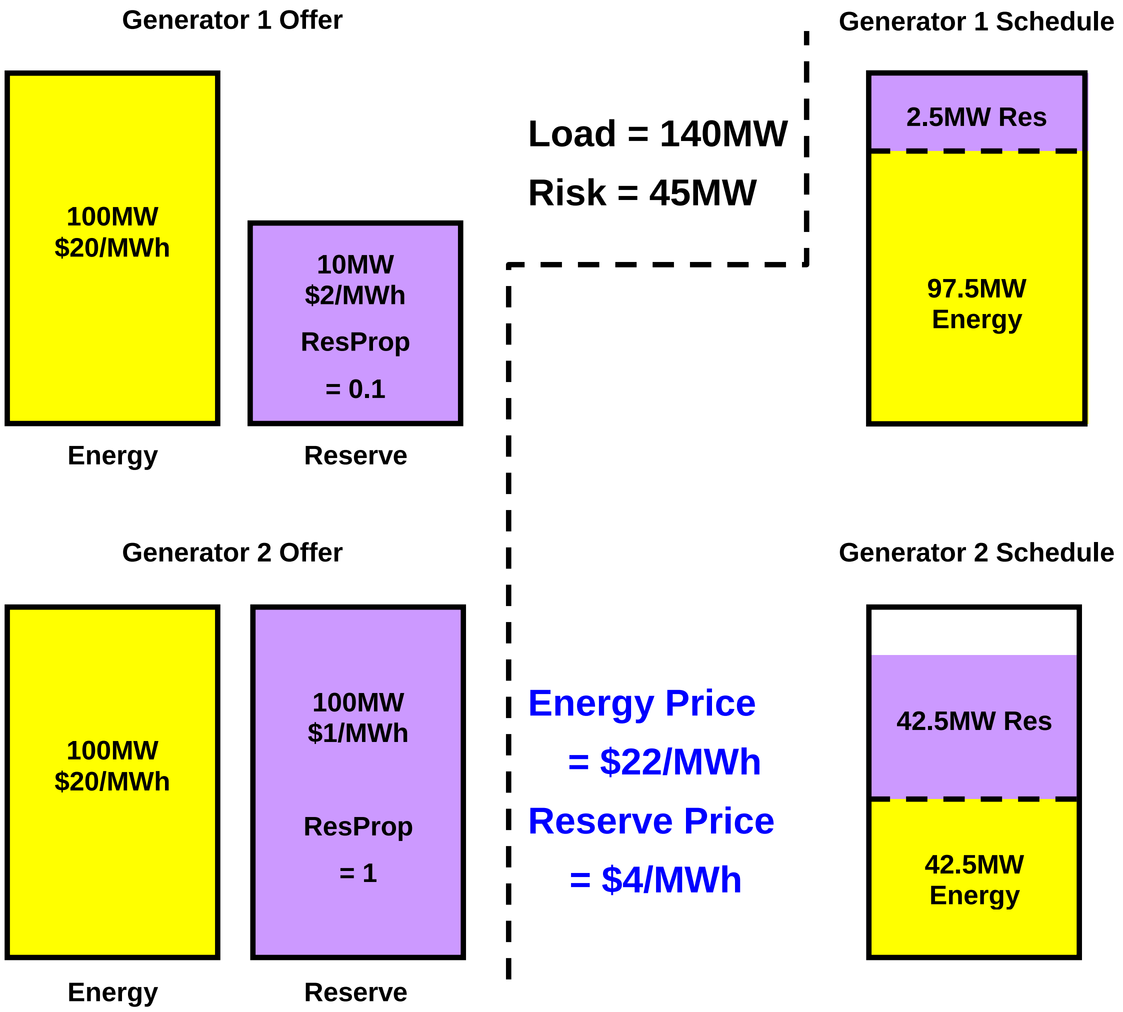
The energy-reserve trade-off model can also be depicted in the diagram as below:



The MCE of the NEMS dynamically models the system risk, i.e., reserve requirement, based on the single contingency of the largest generation. However, in such a simplified system, it is not possible to employ the same dynamic model. Hence for purposes of illustration, the system risk, together with the load, is set arbitrarily as follows:

- the load is 140MW
- the system risk is 45MW

A mathematical model representing the above system is built in the MCE. After solving, the solution is as follows:



G1 offers cheap energy but expensive reserve, while G2 offers cheap reserve but expensive energy. Therefore, the ideal solution is to get all of the energy from G1, and all of the required reserve from G2.

However, due to the constraints between energy and reserve, this is not possible. Take G2 for example. In order to get 1MW of reserve, its energy must be dispatched 1MW first. This makes the solution less clear-cut as a global cost-benefit analysis is required before the optimal solution can be achieved. In light of the complexity of the trade-off, the MCE is used to discover the optimal point.

The following is what the MCE tells us:

1. G1 is dispatched 97.5MW of energy. The reserve availability at this energy level is constrained by the energy-reserve model, as follows:
    a. reserve proportion constraint: Res <= 97.5 * 0.1 = 9.75MW
    b. maximum reserve constraint: Res <= 10MW
    c. reserve generation maximum constraint: Res <= 100 – 97.5 = 2.5MW
2. In order to meet all the above constraints, the maximum available reserve is 2.5MW. Therefore 2.5MW of reserve is cleared from G1 by the solver.
3. G2 is dispatched 42.5MW energy. The reserve availability at this energy level is constrained by the energy-reserve model, as follows:
    a. reserve proportion constraint: Res <= 42.5 * 1 = 42.5MW
    b. reserve generation maximum constraint: Res <= 100 – 42.5 = 57.5MW
4. The smaller of the two is 42.5MW, which is fully cleared by the solver.
5. After re-running the case with one more MW added onto the load, it is found that the next MW is covered by 0.5MW from G1 (costing $20/MWh) and 0.5MW from G2 (costing $25/MWh). As a result, G1’s reserve schedule is depressed by 0.5MW (saving $2/MWh), and G2’s cheaper reserve can be dispatched another 0.5MW (costing $1/MWh). The net cost is: (20 * 0.5) + (25 * 0.5) – (2 * 0.5) + (1 * 0.5) = $22/MWh. Hence, the energy price is $22/MWh.
6. After re-running the case with one more MW added onto the risk, it is found that the next MW is covered by 0.5MW from G1 (costing $2/MWh) and 0.5MW from G2 (costing $1/MWh). As a result, G1’s energy schedule is depressed by 0.5MW (saving $20/MWh), and G2’s energy schedule is increased by another 0.5MW (costing $25/MWh). The net cost is: (2 * 0.5) + (1 * 0.5) – (20 * 0.5) + (25 * 0.5) = $4/MWh. Hence the reserve price is $4/MWh.

Note that neither the energy nor reserve prices are derived directly from the offers of Generators 1 or 2. These prices are the result of co-optimisation between energy and reserve. Although Generator 1 offered 100MW at a cheaper (than marginal) price, it is not cleared at its full amount. The result seems even odder for Generator 2, as the cleared energy price is lower than its offered price.

It is easier to understand the insufficient energy clearance on Generator 1, because of the reserve generation maximum constraint effect. The energy and reserve dispatch from a certain unit in total cannot exceed its physical capability. Generator 1 may not complain either, because it is gaining profits from both its energy and reserve.

Generator 2, however, will not be happy to see itself in such a ‘loss’ position. For every MW of energy it provides, Generator 2 has to fork out $3. Nevertheless, a closer look reveals that Generator 2 is not really losing money, because its profit from reserve offsets any loss from energy. The seemingly unreasonable dispatch is a result of the reserve proportion constraint.

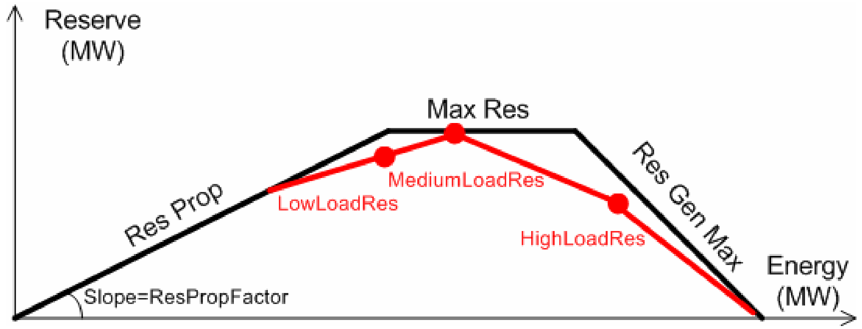
- For each MW of energy dispatched from Generator 2, the genco loses $3, i.e., $25 – $22 = $3.
- However, for each MW of energy dispatch, one MW of reserve is made available as a result. Since the marginal price for reserve is $4/MWh, this MW of reserve scheduled from Generator 2 gains an extra profit of $3, i.e., $4 – $1 = $3.

The loss and profit break even and therefore Generator 2 is not generating at a loss.

The reserve proportion constraint is just one of the many constraints existing in the MCE. Other constraints, such as reserve envelope constraint, may have a similar impact on the NEMS market. Although out-of-merit-order dispatch may result from such constraints, the market participants can be assured that they will never generate at loss.

4.0 Case Study

To gain a more accurate result, the NEMS models the energy-reserve relationship as a multi-segment model, and therefore there are more constraints involved (refer to Appendix A for more details). The NEMS model is depicted in the diagram:



The MCE has dozens of other constraints as well, all of which contribute to the optimal result. Therefore, an analysis of a real case is more complicated and requires a full appreciation of the MCE modelling.

4.1 Dispatch result

The particular real-time dispatch run queried by the market participant is studied in this section. In order to protect sensitive information about the market participant, the date and period of the run are not disclosed and the data have been disguised to some extent. The dispatch result of the relevant generating units follows.

Energy	*(Demand = 3565.518MW, USEP = $158.69/MWh)*				
Facility	**MNN**	**Cleared (MW)**	**Block Price**	**Block Spare (MW)**	**Next Block Price**
G1	**$157.88**	278.448	$126.00	6.552	$146.00
G2	**$157.69**	153.521	$176.00	5.479	$191.00

Regulation	*(Req. = 100MW, Cleared Price = $63.49/MWh)*			
Facility	**Cleared (MW)**	**Block Price**	**Block Spare (MW)**	**Next Block Price**
G1	**4**	$5.00	0	$1,500.00
G2	**8**	$5.00	0	--

Primary Reserve	*(Req. = 256.182MW, Cleared Price = $248.40/MWh)*							
Facility	**Cleared (MW)**	**Block Price**	**Block Spare (MW)**	**Next Block Price**	**Eff Factor**	**ResProp Max**	**Res Env Limit**	**Risk Posed**
G1	**38.874**	$0.01	3.126	--	0.85	45.665	38.874	240.138
G2	**17.962**	$0.02	2.038	--	0.55	17.962	20	96.223

Secondary Reserve	*(Req. = 264.648MW, Cleared Price = $1.04/MWh)*							
Facility	**Cleared (MW)**	**Block Price**	**Block Spare (MW)**	**Next Block Price**	**Eff Factor**	**ResProp Max**	**Res Env Limit**	**Risk Posed**
G1	**45**	$0.01	0	--	0.85	49.007	45	252.519
G2	**24.256**	$0.02	2.744	--	0.55	24.256	27	102.683

Contingency Reserve	*(Req. = 504.750MW, Cleared Price = 0$26.32/MWh)*								
Facility	**Cleared (MW)**	**Block Price**	**Block Spare (MW)**	**Next Block Price**	**Eff Factor**	**ResProp Max**	**Res Env Limit**	**Res Ramp limit**	**Risk Posed**
G1	**50**	$0.01	0	$36.84	0.95	169.018	131.552	149.287	488.922
G2	**55.046**	$0.01	16.954	--	0.95	64.939	65.021	55.046	308.722

Following is the reserve envelope standing data for the units in question, which is used by the multi-segment energy-reserve model:

G1	**LowLoadRes Point**	**MediumLoadRes Point**	**HighLoadRes Point**	**ResGenMax Point**
Energy	255	307.5	<hidden>	<hidden>
Primary Reserve	42	35	<hidden>	<hidden>
Secondary Reserve	45	45	<hidden>	<hidden>
Contingency Reserve	155	102.5	<hidden>	<hidden>

G2	**LowLoadRes Point**	**MediumLoadRes Point**	**HighLoadRes Point**	**ResGenMax Point**
Energy	170	<hidden>	<hidden>	<hidden>
Primary Reserve	20	<hidden>	<hidden>	<hidden>
Secondary Reserve	27	<hidden>	<hidden>	<hidden>
Contingency Reserve	72	<hidden>	<hidden>	<hidden>

Note that data that is not be used in the computation of this case are hidden, protect the identity of the market participant.

4.1 Why is G1 dispatched below its offer?

G1 is constrained by the multi-segment reserve envelope constraint, for both primary and secondary reserve. Although the segment in the secondary reserve envelope constraint is flat, the segment in the primary reserve envelope constraint has a negative slope. Therefore, the more energy that is scheduled from this unit, the less primary reserve that would become available. As a result, the energy is depressed to make room for primary reserve. The cost-benefit analysis is conducted as follows:

- The next MW of energy dispatched from this unit generates a saving of ($157.88 **–** $126.00) = $31.88.
- The available primary reserve, when the energy output is 278.448MW, is 38.874MW[1]. However, if the energy output increases to 279.448MW, i.e., one MW more, the available reserve is only 38.740MW. That is a reduction of 0.134MW, or an equivalent *effective* primary reserve of 0.134 * 0.85 = 0.114MW.
- The cleared primary reserve price is $248.40/MWh, while the offer from this unit is just $0.01/MWh. Hence, the reduction of available primary reserve will incur an additional cost of ($248.40 – $0.01) * 0.114 = $28.32.
- This unit is a combined cycle gas turbine (CCGT) which has a GT damping effect. Every MW of energy increment will add pressure on the primary reserve market by 0.015MW[2]. This incurs an additional cost of $248.40 * 0.015 = $3.73.
- The total additional cost is $28.32 + $3.73 = $32.05, which is slightly higher than the saving ($31.88). Hence, it makes no economic sense to dispatch more energy from this unit.
- Should the energy dispatch go to the next offer block, i.e., with an offer price of $146, the saving would be much less than the cost, which makes the dispatch even more non-optimal.

Let’s take this a step further: since the next MW of energy costs more than the profit, why not dispatch less from this unit so as to achieve more savings? Another cost-benefit analysis provides an explanation:

- If this unit is dispatched one MW less of energy, that would incur an additional cost of ($157.88 **–** $126.00) = $31.88
- The available primary reserve, when the energy output is 278.448MW, is 38.874MW. However, if the energy output is reduced to 277.448MW, i.e., one MW less, the available reserve would be increased to 39.007MW. That is an increment of 0.133MW, or an equivalent *effective* primary reserve of 0.133 * 0.85 = 0.113MW.
- The cleared primary reserve price is $248.40/MWh, while the offer from this unit is just $0.01/MWh. Hence, the increment of available primary reserve would generate a saving of ($248.40 – $0.01) * 0.113 = $28.08.
- This unit is a combined cycle gas turbine which has the GT damping effect. Every MW of energy decrement would release pressure on the primary reserve market by 0.015MW. This would produce an additional saving of $248.40 * 0.015 = $3.73
- The total saving would be $28.08 + $3.73 = $31.81, which is slightly less than the additional cost ($31.88). Similarly, it would make no economic sense to dispatch less energy from this unit.

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[1] This figure can be derived by using the LowLoadRes Point (255, 42) and the MediumLoadRes Point (307.5, 35).

[2] This is the GT Damping factor embedded in the risk calculation. Refer to the Market Rules for more details.

Therefore, the present dispatch scheme on G1 is the best available option.

4.2 Why is G2 dispatched above its offer?

G2 is constrained by reserve proportion constraint for primary and secondary reserves (refer to Appendix A for more details). Therefore, the more energy scheduled from this unit, the more reserve that would become available. As a result, the energy is pushed up to avail more primary and secondary reserve. The cost-benefit analysis is conducted as follows:

- Every MW of energy depressed from this unit generates a saving of ($176 – $157.69) = $18.31.
- The available primary reserve (with a reserve proportion factor of 0.117), when the energy output is 153.521MW, is 17.962MW. However, if the energy output decreases to 152.521MW, i.e., one MW less, the available reserve is reduced to 17.845MW. That is a decrement of 0.117MW, or an equivalent *effective* primary reserve of 0.117 * 0.55 = 0.064MW.
- The cleared primary reserve price is $248.40/MWh, while the offer from this unit is just $0.02/MWh. Hence, the decrement of available primary reserve would incur an additional cost of ($248.40 – $0.02) * 0.064 = $15.98.
- The available secondary reserve (with a reserve proportion factor of 0.158), when the energy output is 153.521MW, is 24.256MW. However, if the energy output decreases to 152.521MW, i.e., one MW less, the available reserve is reduced to 24.098MW. That is a decrement of 0.158MW, or an equivalent *effective* primary reserve of 0.158 * 0.55 = 0.087MW.
- The cleared secondary reserve price is $1.04/MWh, while the offer from this unit is just $0.02/MWh. Hence, the decrement of available primary reserve would incur an additional cost of ($1.04 – $0.02) * 0.087 = $0.09.
- This unit is also constrained by contingency reserve ramping (refer to Appendix A for more details). With a reserve proportion factor of 0.423, every MW of energy reduction constrains the contingency reserve availability by (0.423 – 0.333 [3]) = 0.09MW, or an equivalent *effective* contingency reserve of 0.09 * 0.95 = 0.086MW
- The cleared contingency reserve price is $26.32/MWh, while the offer from this unit is just $0.01/MWh. Hence, the decrement of available primary reserve would incur an additional cost of ($26.32 – $0.01) * 0.086 = $2.25.
- The total additional cost is $15.98 + $0.09 + $2.25= $18.32, which is roughly the same as the saving, i.e., $18.31. Taking into consideration the rounding errors, we can say the cost and the benefit are equivalent in this case. Hence, it makes no economic sense to dispatch more (or less) energy from this unit. The present dispatch scheme on G2 is the best available option.

Both puzzles are now resolved. This description demonstrates that the MCE is always trying to find the optimal solution based on all of the constraints that the system knows.

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[3] This is the reserve response ration for the contingency reserve. Please refer to the Market Rules for more details.

5.0 Conclusion

In an electricity market where optimal dispatch is sought for energy as well as reserve and regulation, the energy dispatch may seem to be out of merit order under some circumstances. However, it is exactly this product-specific out-of-merit-order-dispatch that makes the solution optimal over the entire set of energy products. By appreciating the root causes of such a result, market participants may be able to better respond to the situation the next time that they receive a dispatch outside of their expectations.

Glossary

genco, generation company
A company that generates electricity.

MCE, market clearing engine
The software used in the NEMS to discover dispatch schedules and prices.

MOD, merit order dispatch
Dispatch in the order of offered price where cheaper offers are cleared first.

NEMS, National Electricity Market of Singapore

The Singapore electricity market.

OOMOD, out-of-merit-order dispatch
A situation where merit order dispatch is disrupted with the result that cheaper offers are not necessarily cleared first.

Appendix A Market Rules

The Market Rules Appendix 6.D has various formulas that are relevant to this discussion, as reproduced below.

D.17.2.3 Reserve Proportion Constraint:

$$\text{RawReserve}_r - \text{ExcessRawReserve}_r \leq \text{ReserveProportion}_r \times \text{Generation}_{g(r)}$$

$$\{\, r \in \text{GENRESERVEOFFERS} \}$$

D.17.2.5 Reserve Generation Segment 1

$$\text{RawReserve}_r - \text{ExcessResGenSegment1}_r \leq \text{HighLoadReserve}_r + \text{Slope}$$
$$\text{x}\ (\text{Generation}_{g(r)} - \text{HighLoad x StandingReserveGenerationMax}_{g(r)})$$
$$\{\, r \in \text{GENRESERVEOFFERS} \}$$

where :

$$\text{Slope} = -\text{HighLoadReserve}_r\ /\ (\text{StandingReserveGenerationMax}_{g(r)}$$
$$- \text{HighLoad x StandingReserveGenerationMax}_{g(r)})$$

D.17.2.6 Reserve Generation Segment 2

$$\text{RawReserve}_\text{r} - \text{ExcessResGenSegment2}_\text{r} \leq \text{MediumLoadReserve}_\text{r} + \text{Slope}$$
$$\text{x}\ (\mathit{Generation}_{\text{g(r)}} - \text{MediumLoad x StandingReserveGenerationMax}_{\text{g(r)}})$$
$$\{\, r \in \text{GENRESERVEOFFERS} \}$$

where:

$$\text{Slope} = (\text{HighLoadReserve}_r - \text{MediumLoadReserve}_r)\ /\ (\text{HighLoad}$$
$$\text{x StandingReserveGenerationMax}_{g(r)} - \text{MediumLoad x StandingReserveGenerationMax}_{g(r)})$$

D.17.2.7 Reserve Generation Segment 3

$$\text{RawReserve}_r - \text{ExcessResGenSegment3}_r \leq \text{LowLoadReserve}_r + \text{Slope}$$
$$\text{x}\ (\text{Generation}_{g(r)} - \text{LowLoad}_{g(r)})$$
$$\{\, r \in \text{GENRESERVEOFFERS} \}$$

where :

$$\text{Slope} = (\text{MediumLoadReserve}_r - \text{LowLoadReserve}_r) / (\text{MediumLoad} \times \text{StandingReserveGenerationMax}_{g(r)} - \text{LowLoad}_{g(r)})$$

D19.2 Combined ramping, reserve and regulation constraints

D19.2.1 Reserve Ramp Constraint:

$$\text{RawReserve}_r + \text{ReserveResponseRatio}_r \times (\text{Generation}_{g(r)} - \text{StartGeneration}_{g(r)}) - \text{ExcessResRamp}_r \leq \text{MaxResponse}_r$$

$$\{r \in \text{GENRESERVEOFFERS}, \text{ where ReserveResponsePeriod}_{c(r)} > \text{CombinedRampThreshold}\}$$

D19.2.2 Reserve Proportion Ramp Constraint:

$$\frac{\text{RawReserve}_r + \text{ReserveResponseRatio}_r \times (\text{Generation}_{g(r)} - \text{StartGeneration}_{g(r)})}{- \text{ExcessResPropRamp}_r \leq \text{ReserveProportionCombined}_r \times \text{Generation}_{g(r)}}$$

$$\{r \in \text{GENRESERVEOFFERS}, \text{ where ReserveResponsePeriod}_{c(r)} > \text{CombinedRampThreshold}\}$$