पावर सिस्टम ऑपरेशन कारपोरेशन लिमिटेड
(भारत सरकार का उद्यम)
POWER SYSTEM OPERATION CORPORATION LIMITED
(A Govt. of India Enterprise)

पंजीकृत एवं केन्द्रीय कार्यालय : प्रथम तल, बी-9, कुतुब इंस्टीट्यूशनल एरिया, कटवारिया सराय, नई दिल्ली-110016
Registered & Corporate Office : Ist Floor, B-9, Qutab Institutional Area, Katwaria Sarai, New Delhi -110016
CIN : U40105DL2009GOI188682, Website : www.posoco.in, E-mail : posococc@posoco.in, Tel.: 011- 41035696, Fax : 011- 26536901

संदर्भ संख्या : पोसोको/एनएलडीसी/कें.वि.वि.आ

दिनाँक: 31st January, 2017

सेवा मे,

सचिव,

केंद्रीय विनियामक आयोग,
तीसरी मंजिल, चंद्रलोक बिल्डिंग,
३६ जनपथ, नई दिल्ली -११०००११

विषय: POSOCO's comments on Draft Fifth Amendment to IEGC,2010 on behalf of all RLDCs/NLDC

Ref: CERC Public notice No. L-1/18/2010/CERC dated 9th Dec 2016
CERC Public notice No. L-1/18/2010/CERC dated 3rd Jan 2017

महोदया,

With reference to the above mentioned notices of the Hon'ble Commission, the views/suggestions of POSOCO on behalf of all RLDCs/NLDC on the draft fifth amendment to IEGC, 2010 notified on 09th Dec 2016 are enclosed herewith for you kind perusal.

सादर धन्यवाद,

आपका आभारी

एस·आर· नरसिम्हन

(एस आर नरसिंहन)
अपर महाप्रबंधक (प्रणाली प्रचालन)
एन एल डी सी

Power System Operation Corporation Limited
New Delhi

31st January 2017

Sub: **POSOCOs comments on behalf of all RLDCs/NLDC on the 5th amendment to Indian Electricity Grid Code, 2010 notified by the Hon'ble CERC on 9th Dec 2016**

1.0 Background:

The amendments proposed by the Commission are a welcome step for reliable and economic operation of the Indian Power System considering the large scale integration of Renewable Energy (RE) in India.

The comments are in two sections; **Section A** contains suggestions on the draft amendments and areas related to while **Section B** covers suggestions apart from the present draft amendments but are essential for reliable and economic operation of the electricity grid besides consolidating the various orders given by the Hon'ble Commission in the recent past.

Section A

1) **Need to suitably replace the terms Free Governor Mode of Operation (FGMO) and Restricted Governor Mode of Operation (RGMO):** RGMO term in IEGC in vogue since May 2010 has served the purpose and is required to be replaced**.** These terms are not used internationally and may be replaced with '**Primary frequency control with droop'.** This had also been highlighted in the presentation made on 16th March 2015 by M/s Solvina (responsible for the pilot project in governor testing in Northern region) to the Committee constituted by Hon'ble Commission headed by Sh A Velayutham.

   The main purpose of primary frequency control is to resist any change in frequency in any direction automatically without any operator intervention. Primary frequency control is not envisaged to maintain frequency at 50 Hz. The Restricted Governor Mode of Operation, introduced by the Commission in May 2010, being a non-standard solution, led to several generators going for retrofits with little and different understanding of the stipulation in the Grid Code. This is also evident from the above referred presentation made by M/s Solvina and is enclosed at Annexe-I for perusal.

Hence, it is suggested that all references to Free Governor Mode of Operation/Restricted Governor mode of Operation in section 5.2 (f) of the IEGC may be dropped and replaced uniformly by 'Primary Frequency Control with droop'. Section 5.2 (f) (ii)(d) may be dropped, while 5.2 (f)(ii) (b) may be replaced with ***'Dead band of governor should not exceed +/-0.03 Hz'***. In fact, IEGC Clause 5.2(f)(ii)(d) also states in this line only which is quoted below:
"After stabilization of frequency around 50 Hz, the CERC may review the above provision regarding the restricted governor mode of operation and free governor mode of operation may be introduced. "

Today, the All India electricity grid is operating in a band 49.90-50.05 Hz for nearly 75% of the time with the minimum frequency rarely touching 49.70 Hz and the maximum rarely touching 50.30 Hz. Hence the time is appropriate to move forward and introduce Primary Frequency Control with droop as suggested above.

2) Regulation 2.(1) (sss) 'Definition' of Spinning Reserves

Proposed Amendment

"The Capacity which can be activated on the direction of the system operator and which is provided by devices including generating stations/units, which are synchronized to the grid and able to effect the change in active power"

Suggestion

The term 'unused' may be prefixed to 'capacity'. Further considering that Ancillary Services is many a times used to trigger units under Reserve ShutDown, similar definition of 'non-spinning reserves' may be added as under:

*"**Non-spinning reserves:** The capacity which can be activated on the direction of the system operator and which is provided by devices including generating stations/units, which are not synchronized to the grid and are under reserve shut down (at the instant of invoking into operation) based on system requirement or system operator direction."*

Further, the term 'System Operator' though widely used, could be formally defined as ***"System Operator****: Any load dispatch centre viz. the National Load Despatch Centre established under section 26(1) of the Act or any Regional Load Despatch Centre established under section 27(1) of the Act or any State Load Despatch Centre established under section 31(1) of the Act engaged in the function of power system operation;"*

Further the definition of primary, secondary and tertiary reserves may also be included in the grid code as defined in Section B of this document.

3) Amendment of Section 2.2.1 (m) through additions:

The additions proposed in the draft amendment may be added as Section 2.2.2 (iii) instead of above section considering that section 2.2.1 is basically a reproduction from the National Load Despatch Centre Rules 2005, notified by Ministry of Power. Further 2.2.2 (iii) may be renumbered as 2.2.2 (iv).

4) Amendment of regulation 5.2 (f) (ii) (a)

Proposed amendment:

"Regulation 5.2 (f)(ii) (a) may be substituted as follows:
"There should not be any reduction in generation in case of improvement in grid frequency below 50.05 Hz (for example, if grid frequency changes from 49.9 to 49.95 Hz, or from 50.00 to 50.04 Hz there shall not be any reduction in generation). For any fall in grid frequency, generation from the unit should increase as per generator droop upto a maximum of 5% of the generation subject to ceiling limit of 105% of the MCR of the unit having regard to machine capability".

Suggestion: Considering the comment on RGMO/FGMO at (1) above, the above clause may be reworded as

"~~There should not be any reduction in generation in case of improvement in grid frequency below 50.05 Hz (for example, if grid frequency changes from 49.9 to 49.95 Hz, or from 50.00 to 50.04 Hz there shall not be any reduction in generation).~~ For any fall in grid frequency, generation from the unit should increase as per generator droop ~~upto a maximum of~~ **by at least** *5% of the ~~generation~~* ***MCR*** *subject to ceiling limit of 105% of the*

MCR of the unit having regard to machine capability ***and also subject to the limitations for hydro stations****".*"

This is considering that station schedule varies throughout the day and the operator cannot be calculating and changing the load limiter value to 5% of the current generation level.

Further in case of less declaration (less than Normative DC) due to any constraints, ensuring margins for Primary response may not be possible by RLDC. Hence, suitable additional clause modification may be done such that generators shall ensure the margins in case of less declaration through appropriate margins in DC itself.

Note to be added in section 5.2 (f) (iii) in respect of wind and solar:
The draft CEA Technical Standards for Connectivity to the grid envisage solar and wind
generators also to provide primary response. Suitable note may therefore be added to
the above IEGC section so that there is no blanket waiver from primary response for wind
and solar generators.

5) **Note to be added in section 5.2 (f) (iii) in respect of wind and solar:**

The draft CEA Technical Standards for Connectivity to the grid envisage solar and wind generators also to provide primary response. Suitable note may therefore be added to the above IEGC section so that there is no blanket waiver from primary response for wind and solar generators.

6) **Proposed new para to be added at the end of clause 5.2 (h)**

Proposed Amendment

"For the purpose of ensuring sustainable primary response, and RLDCs/SLDCs shall not schedule the generating units beyond ex-bus generation corresponding to 100% of the Installed capacity……………………………….."

Suggestion

i. Installed capacity and MCR are defined at generator terminal, whereas RLDCs prepares schedule at the ex-bus of generator. Therefore in order to have clarity on the maximum power to be scheduled and power to be kept for primary response, ex-bus generation schedule ceiling corresponding to 100% of the Installed capacity less normative auxiliary consumption may be specified. Further, Hydro Generating Stations may be required to run till the overload capacity, at times, to avoid spillage of water and to manage peak load. Further, while deciding Normative Annual Plant Availability (NAPF) for hydro generating stations, Hon'ble Commission has already taken into cognizance of overload capability. Therefore, it is proposed that overflowing hydro generating stations may be excluded from the ambit of this proposed amendment. Considering the above, following changes are suggested:

Suggested modified para

"For the purpose of ensuring sustainable primary response,~~ and RLDCs/SLDCs shall not schedule the generating unit s beyond ex-bus generation corresponding to 100% of the Installed capacity~~ ***ISGS (excluding overflowing hydro generators) shall limit ex bus capability for the next day upto installed capacity less normative auxiliary consumption. Further, these stations should ensure that in real time also, they do not intentionally exceed these values to get benefit, if any, under the Deviation Settlement Mechanism. The margins should be available only to take care of primary frequency response. Over-flowing hydro stations should keep a record of water inflows, reservoir levels, discharge through turbines and spillage and submit the same whenever requested by RLDCs/SLDCs."***

7) Proposed amendments related to changes in scheduling mechanism

In view of the mandate given in the revised Tariff Policy to sell the URS power in the market, Hon'ble Commission has revised the timeline for scheduling process in these amendments from day ahead to two day ahead. The revised timeline for scheduling for day D is as follows:

Activity	Time	Day
DC Declaration	1300 Hrs	D-2
Entitlements to Beneficiaries	1500 Hrs	D-2
Requisition by Beneficiaries	1700 Hrs	D-2
Schedule Revision 0	1900 Hrs	D-2
Requisition of URS	2000 Hrs	D-2
Schedule Revision 1	2100 Hrs	D-2
Schedule Revision 2 (incorporating any sale by ISGS)	1800 Hrs	D-1
Changes in Drawl / Declared Capability to RLDC	2200 Hrs	D-1
Schedule Revision 3 (Final Day–Ahead Schedule)	2300 Hrs	D-1

D-2 = Two Day Ahead
D-1 = Day ahead
D = Day of Operation

A decentralized scheduling process is in place in the country where all participating entities have the liberty to change schedules, i.e., revise drawl schedules / injection schedules based on their requirement. There are no restrictions on the number of revisions that are permissible and this is a continuous and ongoing process. The available un-despatched/un-requisitioned surplus is changing continuously. The proposed amendment also gives the option of calling back the URS at multiple stages of the scheduling process along with option to the generator to sell in the market.

a. Stage 1: Requisition of URS after declaration of tentative schedule by 7 PM of D-2 up to 8 PM of D-2. (These are in line with CERC order in petition no 134/2009 & 310/MP/2015 and considered as reallocation)

b. Stage 2: URS sale in market by generator after communication by the original beneficiary by 12 AM regarding quantum and duration of URS power. (These would be in line with CERC regulations on Short Term Open Access)

c. Stage 3: URS power left after sale in market can be requisitioned by the beneficiaries of the station (similar to stage 1) or scheduled by NLDC under Ancillary Services Framework.

It is clear from the above that there is no limit to the requisition of the URS power which is available in the real time as well (if not sold in market) leading to available URS changing continuously. The option of availing URS power at any time may lead to complexities in scheduling & accounting of URS power and poses an issue in calculations of margins for STOA. Further, it may also lead to disputes when the part URS power is sold in market and part URS power is requisitioned at any time and thereafter some machines at a generating station trip. Therefore, it is proposed to introduce the concept of “**Gate Closure**” in India. It is also understood that the beneficiaries would want the flexibility of availing the URS power at any time as they are paying the fixed charges. A blanket consent for sale of power in case of no communication from the beneficiary (Stage 2 above) is also not justified. Considering all these, following is proposed:

1. Once the tentative schedule is fixed by 7 PM of D-2, other beneficiaries cannot give requisition for the URS power.

2. State can give consent for sale of maximum 50% of their URS in each ISGS in the market. Rest of the entitlement shall take care of tertiary reserves, load forecast error, generation outages etc.

3. In case a state gives consent for sale of 50% of its URS power in market, it cannot recall the same thereafter even if the same is unsold in the market. This unsold power can be sold by the generator in either STOA (24X7 Market) or can be used by NLDC in Ancillary Services.

   In case a beneficiary fails to give consent for sale of its URS power in the market, generator may sell 50% of URS power in the market. Rest 50% shall be reserved for tertiary reserve for that state.

Based on these suggestions, following changes in the amendments are suggested:

Amendment to Principle Regulation 6.5

a. **Clause 8(a) and 8(b) may be deleted and replaced with following clause**

   "Once the tentative net drawl schedule is fixed by 7 PM, original beneficiary can give requisition upto maximum 50% URS power. Rest 50% of the URS shall be available with the ISGS to sell in the market."

b. **Clause 8(c)**

   Suggested Changes

   "ISGS may sell the balance URS power left after completion of the process of ~~requisition by other original beneficiaries of the plant~~ **scheduling,** in the market. The original beneficiary shall communicate by ~~12PM~~ **0000 hrs day ahead** about the quantum and duration of such URS power to ISGS **(with a copy to RLDC)** to enable ISGS sell same in the market. **ISGS may sell up to 50% of beneficiaries URS power in the market or higher depending on the communication from the original beneficiary**. **Rest 50% URS power shall be left with the beneficiary to take care of real time contingencies and tertiary reserves**. If the original beneficiary fails to communicate to ISGS, then the ISGS shall be entitled to sell the **50%** URS power of the beneficiary in the market."

c. **Clause 8(e)**

   Suggested Changes

   After sale in market as under 8(d) above, if any power still remains under URS, the same ~~may~~ **cannot** be requisitioned by the beneficiaries of the station. **This URS power shall be available with the ISGS for either sale in STOA or dispatch under Ancillary Services**.

d. 6.5 (A) (c) may be deleted as any other beneficiary shall not be allowed to give requisition for unallocated power.

In case the suggestions given above are not acceptable to the Hon'ble Commission, then following changes in the proposed amendments may kindly be done for better clarity.

Regulation 6.5 (A) (c)

Proposed Amendment

"……………………..c. In case the un-requisitioned surplus power surrendered by the original beneficiary is requisitioned by the other beneficiaries of the ISGS, it shall be treated as reallocation and the fixed charge and variable charge for such energy exchanged shall be borne by the other beneficiary (ies)."…..

Suggestion: In order to bring clarity that only the beneficiaries who have requisitioned the un-requisitioned surplus power shall bear the fixed and variable charges of such energy, it is proposed to add the same at the end.

Suggested Changes

"In case the un-requisitioned surplus power surrendered by the original beneficiary is requisitioned by the other beneficiaries of the ISGS, it shall be treated as reallocation and the fixed charge and variable charge for such energy ~~exchanged~~ scheduled shall be borne by the other beneficiary (ies) ***who have availed the un-requisitioned surplus power"***

Amendment to Regulation 6.5 Clause 8 (a)

Proposed Amendment

"Original Beneficiaries of an ISGS will have first right to give requisition for the URS power of the ISGS. Such original beneficiaries shall advice RLDCs, through their SLDC, regarding quantum of power and time duration of such drawl out of declared URS of the ISGS, by 8 P.M. In case full URS of an ISGS is requisitioned by more than one original beneficiary, RLDC shall allocate URS proportionately based on the share of these original beneficiaries in the ISGS."

Suggestion: The URS requested may not be in line with share allocation viz, a beneficiary having less share allocation may be requiring more URS power as compared to the beneficiary with higher share allocation. In this context, the CERC

ROP in petition No. 16/SM/2015 regarding scheduling of unscheduled surplus power from the inter-State generating stations is quoted below:

"Where both the generating station and its beneficiaries (surrendering and requesting beneficiaries) give their standing consents in writing to RLDC that the decision of the concerned RLDC will be binding on them with regard to scheduling and dispatch of URS power, ***the concerned RLDC shall schedule such URS power to the requesting beneficiaries in relative proportion to the quantum requested by them.*** *In other cases, RLDCs shall schedule URS power on the basis of the consents submitted by the generating stations in terms of the order dated 5.10.2015."*

Suggested Changes

"Original Beneficiaries of an ISGS will have first right to give requisition for the URS power of the ISGS. Such original beneficiaries shall advice RLDCs, through their SLDC, regarding quantum of power and time duration of such drawal out of declared URS of the ISGS, by 8 P.M. ~~In~~ ***If*** *~~case~~* ***total URS requisitioned*** *~~full URS of~~* ***in*** *an ISGS* ***is more than the available URS due to URS requisitioning*** *~~requisitioned~~ by more than one original beneficiary* ***of that ISGS****, RLDC shall allocate URS proportionately based on the ~~share of these original beneficiaries in the ISGS~~* ***URS quantum requested by the beneficiary(ies) based on the availability"***

8) Amendment to Regulation 6.5 Clause 8 (d)

Proposed Amendment

"*The URS which has been sold and scheduled by ISGS in the market (power exchange or through STOA cannot be called back by the original beneficiary."*

Suggestion: The constituents/RLDC should know how much of their individual beneficiaries surrender quantum is sold in the market, out of the total sell by the ISGS, such that the same cannot be recalled back. Further, the types of STOA transactions may be clearly mentioned.

Suggested Changes

The URS which has been sold and scheduled by ISGS in the market (~~power exchange or through~~ STOA ***Collective or Bilateral****) cannot be called back by the original beneficiary.* ***The Generator shall intimate the details of the URS Quantum of individual beneficiaries, sold in the market, to ensure the same.***

Section B

1. Miscellaneous

a. It has been observed that even after 72 hr trial run, some regional entity generators do not declare commercial operation immediately and continue to inject infirm generation. Following may be added as note after clause 6.3.A.3 of IEGC:

"After generator announces start of 72 hour trial & completes the same, it shall be incumbent on the generator to either declare COD or communicate the deficiencies observed in trial run & intimate likely dates of next trial"

b. There have been instances where the home state drawing power from any ISGS being scheduled by RLDCs does not agree to pay for inter-state transmission charges and losses, citing STU connectivity also at that point. As, any case by case exemption from interstate transmission charges & losses is subjective & may lead to disputes, it is proposed to add following in clause 6.4.2 (c)

"Inter-State transmission charges and losses shall be applicable for scheduling from one regional entity to other regional entity (including embedded entities) in accordance with CERC Regulation on "Sharing of Transmission Charges and Losses in ISTS" Regulation 2010 and any amendment thereof. Accordingly all the transactions scheduled through RLDCs shall be subjected to Point of Connection (POC) injection as well as withdrawal charges and losses."

c. A generating station applies for long term access and medium term open access in advance considering the likely commissioning of generating units. Accordingly, LTA/MTOA is being approved by the CTU. Power Purchase Agreement is also signed considering the likely commissioning of units in future. It may happen that at the time of operationalizing the LTA/MTOA, the total LTA/MTOA quantum is greater than the installed capacity at that time. In such situations, it is desirable that the schedule of that generator is limited to ex-bus installed capacity. Recently, similar case was also encountered with a generating station in Western Region. Therefore, it is proposed to add following after IEGC clause 6.4.14:

"…..If the ex-bus installed capacity or sent out capability of the plant is less than the PPA signed or/and LTA/MTOA operationalized by CTU, then RLDCs shall commence operationalization of schedules limited to the ex-bus installed capacity"

Further, In case of multiple contracts, scheduling priority can be given either based on the date of operationalization of the contract or all contracts scheduled on a pro rate basis. Hon’ble Commission may further give directions in this regard & incorporate it suitably in the IEGC, else it is likely to lead into a number of disputes.

d. The IEGC provides for a limit of maximum 16 revisions for RE generators in a day whereas no such limit for declared capability revision exists for conventional generators. With no limit on the number of revisions for conventional generators, there is no certainty to the states regarding power available during a day. Therefore, it is proposed to limit the number of revisions of a conventional generator to 4 (i.e. 25% of maximum revisions for RE generators). Accordingly following may be added in clause 6.5.18 of IEGC:

   “Provided that the maximum number of declared capability revisions of conventional generators shall be limited to 4 during a day”

e. It has been observed that some states give zero requisition from a central generating station during off peak hour and gives full requisition during peak hour. At times, this leads to a schedule less than technical minimum for these generating stations during off peak hour which poses a challenge to run the machine during off peak hours. Therefore it is suggested that the off peak to peak requisition ratio may be limited to 55%. Accordingly following may be added in clause 6.5.4 of IEGC:

   “Provided that the ratio of off peak to peak drawl schedule given by each beneficiary for each ISGS shall be at least 55%.”

f. It has been observed that gas stations with multiple fuel gives major portion of its declared capacity (DC) for the costliest fuel. Since, states generally would not give requisition for costly fuel, the certification of availability of these generating stations becomes a challenge. Therefore, it is proposed that certain provisions to check gaming in these cases may kindly be included in the grid code.

In addition to these suggestions, it is also felt that the amendments need to suitably factor the developments in the past within the country and worldwide also such as Assessment of Frequency Response Characteristics, Testing of frequency response, Reserves, Ancillary services, Draft amendment to the CEA (Technical Standards for Connectivity to the Grid), Regulations, 2007. Accordingly certain new definitions and provisions related to frequency control are proposed which are attached as Annexure II. Some of the references used to formulate these definitions/provisions are given below:

List of References

a. ENTSOE P1 – Policy 1: Load-Frequency Control and Performance [C], 2009 (https://www.entsoe.eu/fileadmin/user_upload/_library/publications/entsoe/Operation_Handbook/Policy_1_final.pdf)

b. NERC Standard BAL-001-2 – Real Power Balancing Control Performance (http://www.nerc.com/pa/Stand/Reliability%20Standards/BAL-001-2.pdf)

c. NERC Standard BAL-002-1 — Disturbance Control Performance (http://www.nerc.com/files/bal-002-1.pdf)

d. NERC WECC Standard BAL-002-WECC-2 — Contingency Reserve (http://www.nerc.com/files/BAL-002-WECC-2.pdf)

e. NERC standard BAL-001-TRE-1 — Primary Frequency Response in the ERCOT Region (http://www.nerc.com/pa/Stand/Reliability%20Standards/BAL-001-TRE-1.pdf)

f. Glossary of Terms Used in NERC Reliability Standards (http://www.nerc.com/files/glossary_of_terms.pdf)

g. NERC BAL-001-2 – Real Power Balancing Control Performance Standard Background Document, 2013 (http://www.nerc.com/pa/Stand/Project%202010141%20%20Phase%201%20of%20Balancing%20Authority%20Re/BAL-001-2_Background_Document_Clean-20130301.pdf)

h. NERC BALANCING AND FREQUENCY CONTROL: A Technical Document Prepared by the NERC Resources Subcommittee (http://www.nerc.com/docs/oc/rs/NERC%20Balancing%20and%20Frequency%20Control%20040520111.pdf)

i. Draft European Union regulation on establishing a guideline on electricity transmission system operation, 2016 (https://ec.europa.eu/energy/sites/ener/files/documents/SystemOperationGuideline%20final%28provisional%2904052016.pdf)

j. Essential Reliability Services and the Evolving Bulk-Power System— Primary Frequency Response, Issued November 17, 2016 (https://www.ferc.gov/whats-new/comm-meet/2016/111716/E-3.pdf)

Creating
Energy Excellence

- Power System Control and Stability
- Power Plant Testing
- Process Control
- Engineering Management
- Nuclear Power Safety

CERC 16/03/2015 Introduction

Testing of Primary Response of Generating Units

CC-CS/422-CC/CON-2241/3/G8

490 MW thermal unit at Dadri NCTPS
210 MW thermal unit at Dadri NCTPS
216 MW gas turbine unit at Bawana GPS
180 MW hydro unit at Chamera-I HPS
250 MW hydro unit at Tehri HPS

पावर सिस्टम ऑपरेशन
POSOCO

Solvina International

During 2014, Solvina International has carried our test of primary response of five units in India, under a contract with Power Grid /POSOCO.

Reports, soft copies as well as hard copies, were submitted 11/03/2015

Solvina International

Presentation outline

1. Methodology adopted for testing
2. Results of the testing of the units
3. Comments on FGMO and RGMO
4. International practices and regulatory provisions regarding periodic testing of frequency control
5. Suggestions for Control strategies and Regulatory Interventions reg. testing in India

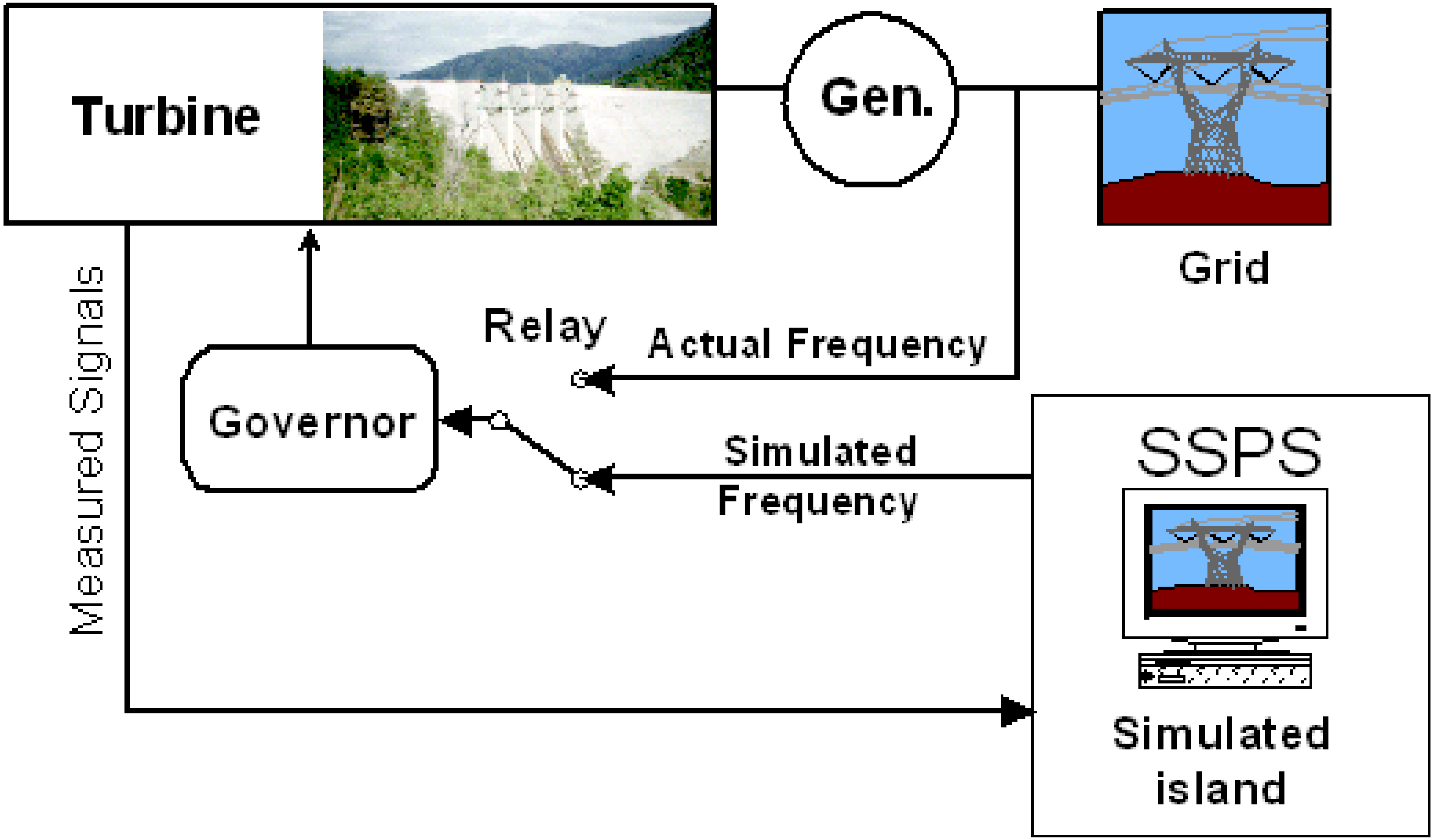
Test principle

By breaking up the control loop for frequency control, any test signal may be injected to study the response of the machine while still synchronized to the main grid (online testing!)

Tests may be carried out

- ”open loop”, with a predefined signal
- ”closed loop”, with a simulated signal depending on the unit output

Test method /SSPS function



FGMO ”primary response”

What is desired to know in normal operation in the large grid is the

- **Magnitude of response (MW/Hz)**

- **Speed of response (Time constant)**

Injecting a frequency step (open loop) gives both these variables in a very clear way.

FGMO ”Islanded systems”

What is desired to know in **Islanded** conditions is the **ability of the unit to respond to load changes and how it can maintain the stability** of the system frequency following different contingencies.

Full scale tests can be made if allowed, but this is both costly and hazardous. Furthermore, rarely the load level may be chosen.

So, by **simulating islanded conditions and giving the simulated frequency to the unit**, islanded conditions can be evaluated.

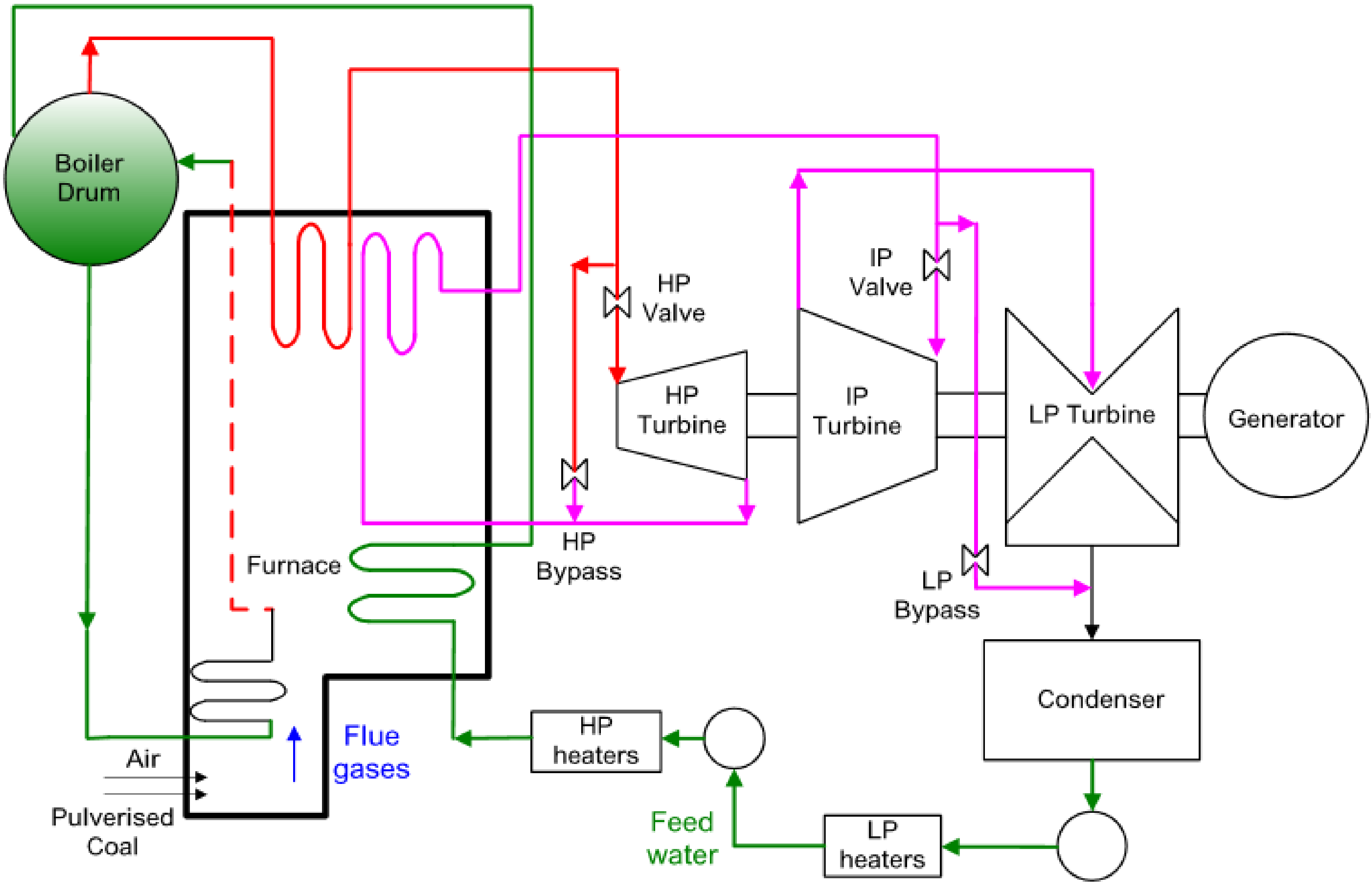
Test results

Unit / Test	FGMO	RGMO	Islanding (FGMO)
Dadri II (490MW)	Expected beavior 196MW/Hz, 15-85s	-	Stable f-control but unstable process
Dadri I (210MW)	Expected behavior, but maybe too reponsive 84MW/Hz, 3-8s	-	Unstable f-control and process
Bawana (216MW)	Expected behavior 110MW/Hz, 5-10s	-	Not tested due to inability to arrange test input
Chamera (180MW)	As Expected 60 MW/Hz, 10-60s	OK, meets grid code	Stable, can manage large load change (>10%)
Tehri, (250MW)	Expected behavior but gate feedback causes nonlinear load response. *50-250MW/Hz*, (125) 100-200s	Works but not as intended in some cases	Stable, can manage large load change (>10%)

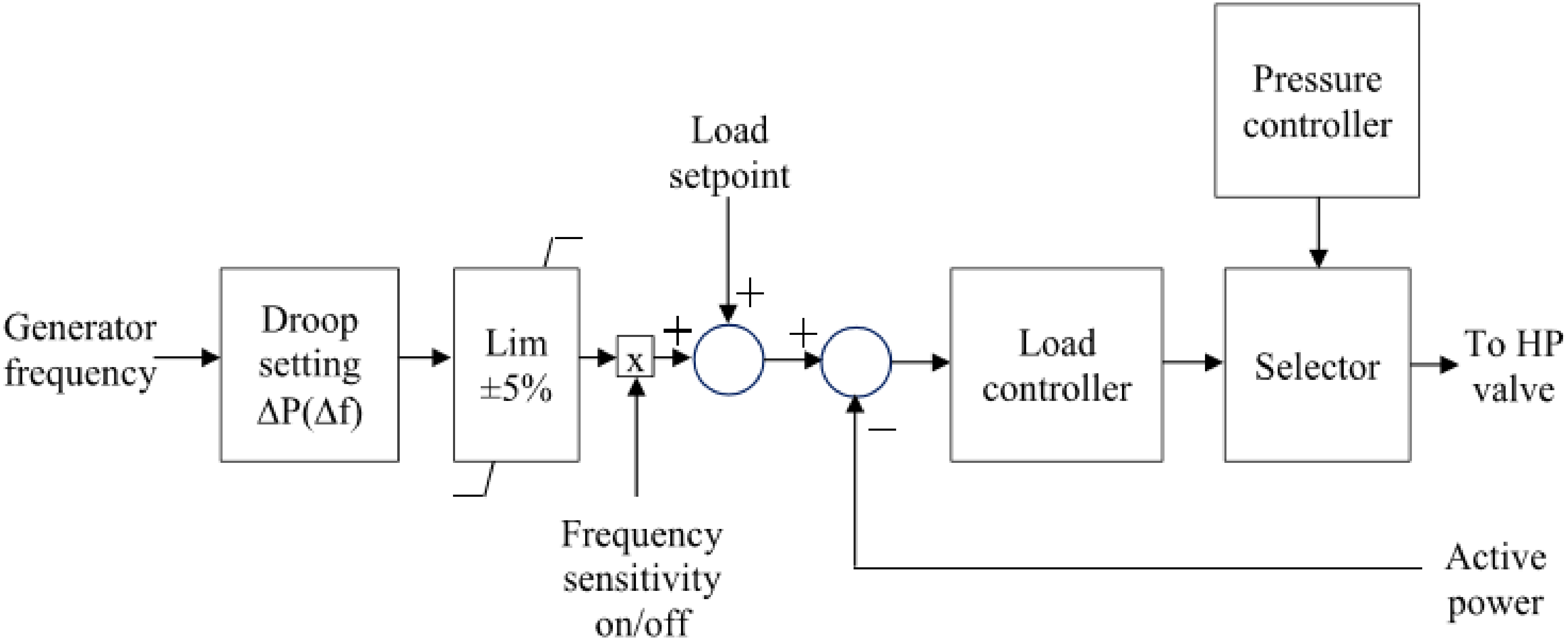
Solvina International

Dadri II, unit 6, 490MW

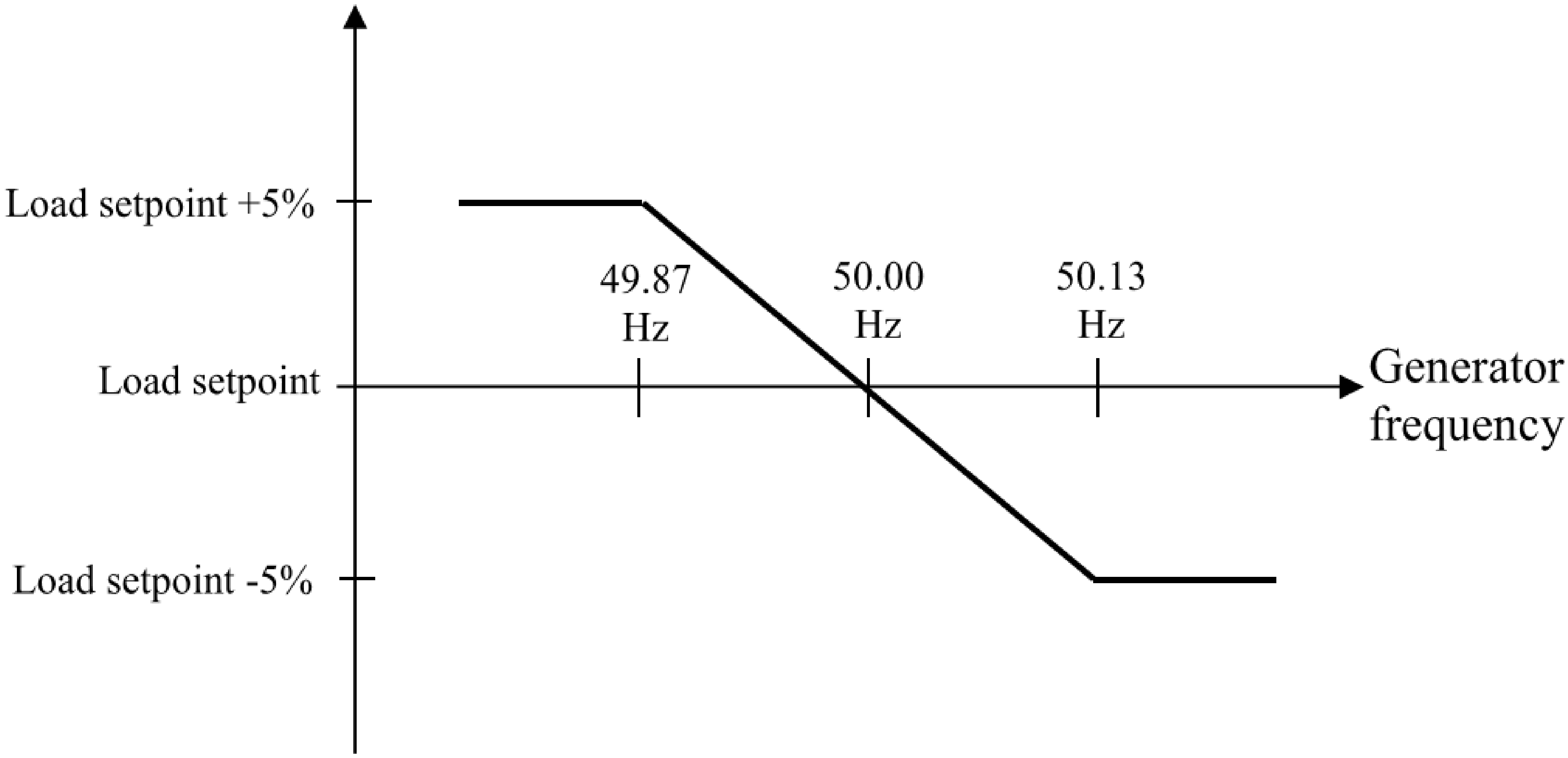
Background: Unit



Background: Governor



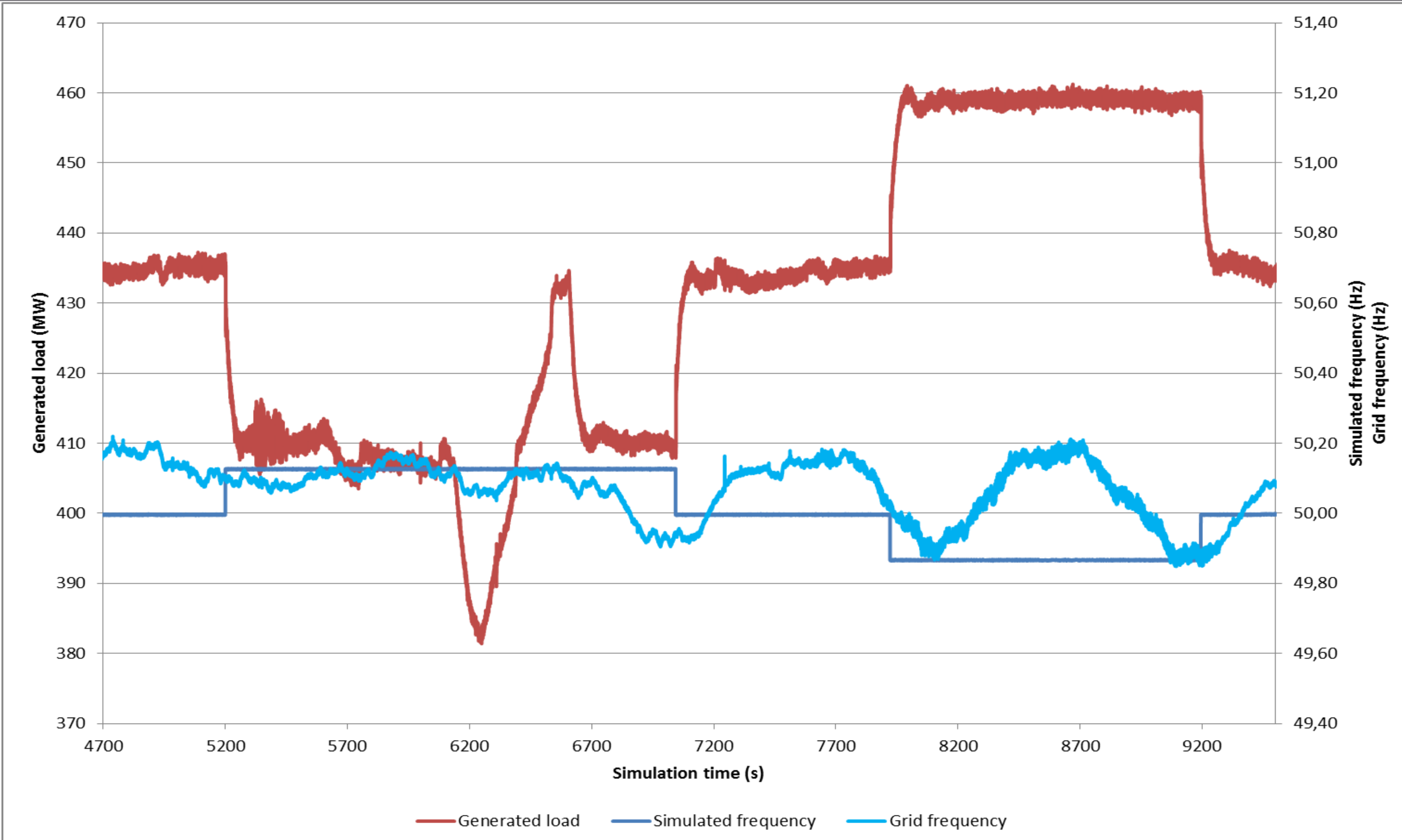
Background: Governor



Step response FGMO

- Responds consistently and according to droop.
- Max response +/- 5%
- Response time 15-85 sec
- Difficult to keep steam pressure within limits
  - Overpressure – bypass opens
  - Underpressure – pressure control takes over and reduces output
- Plant is presently not fit for FGMO in interconnected operation

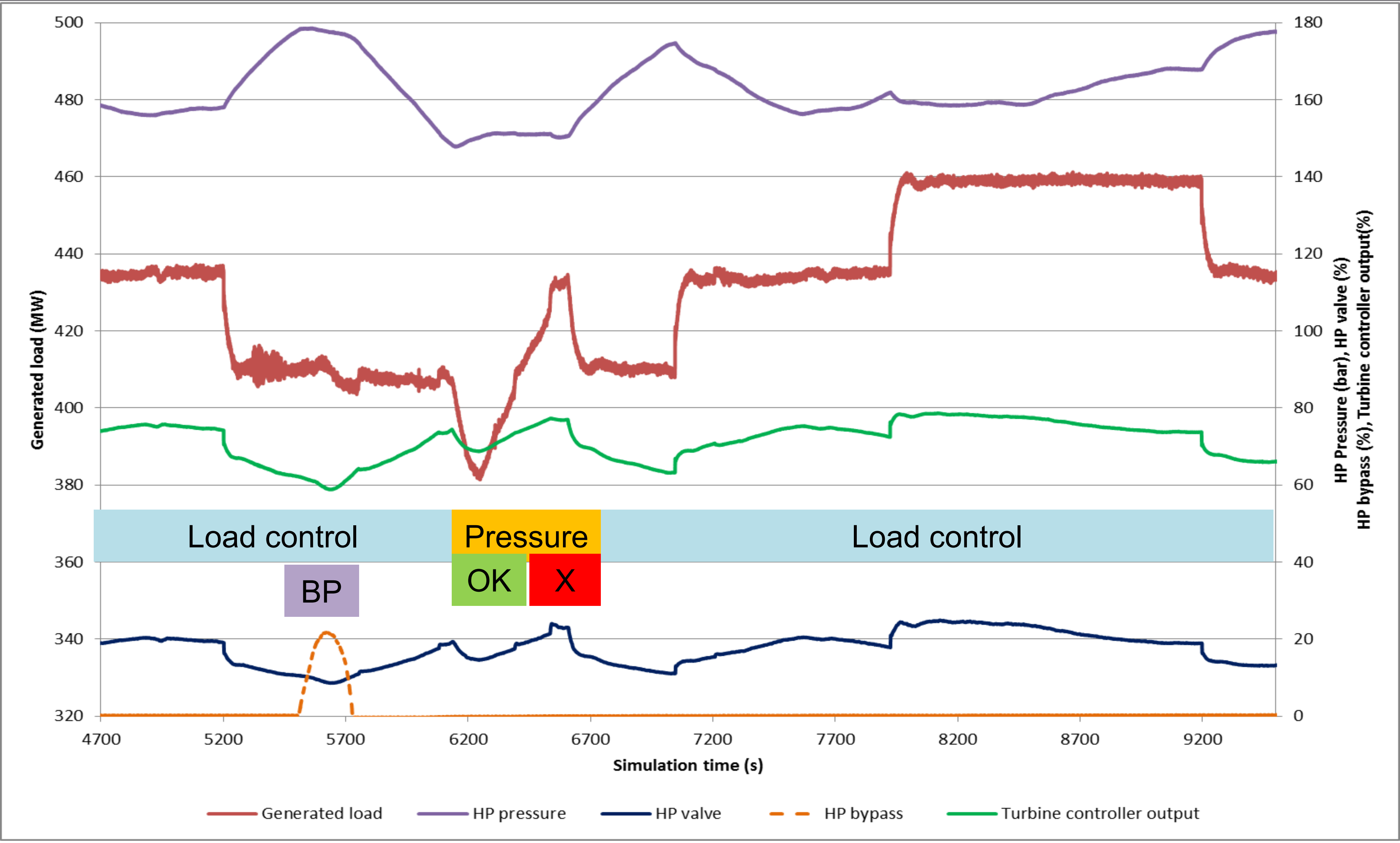
90% part 2



± 0.13 Hz step

Solvina International

90% part 2

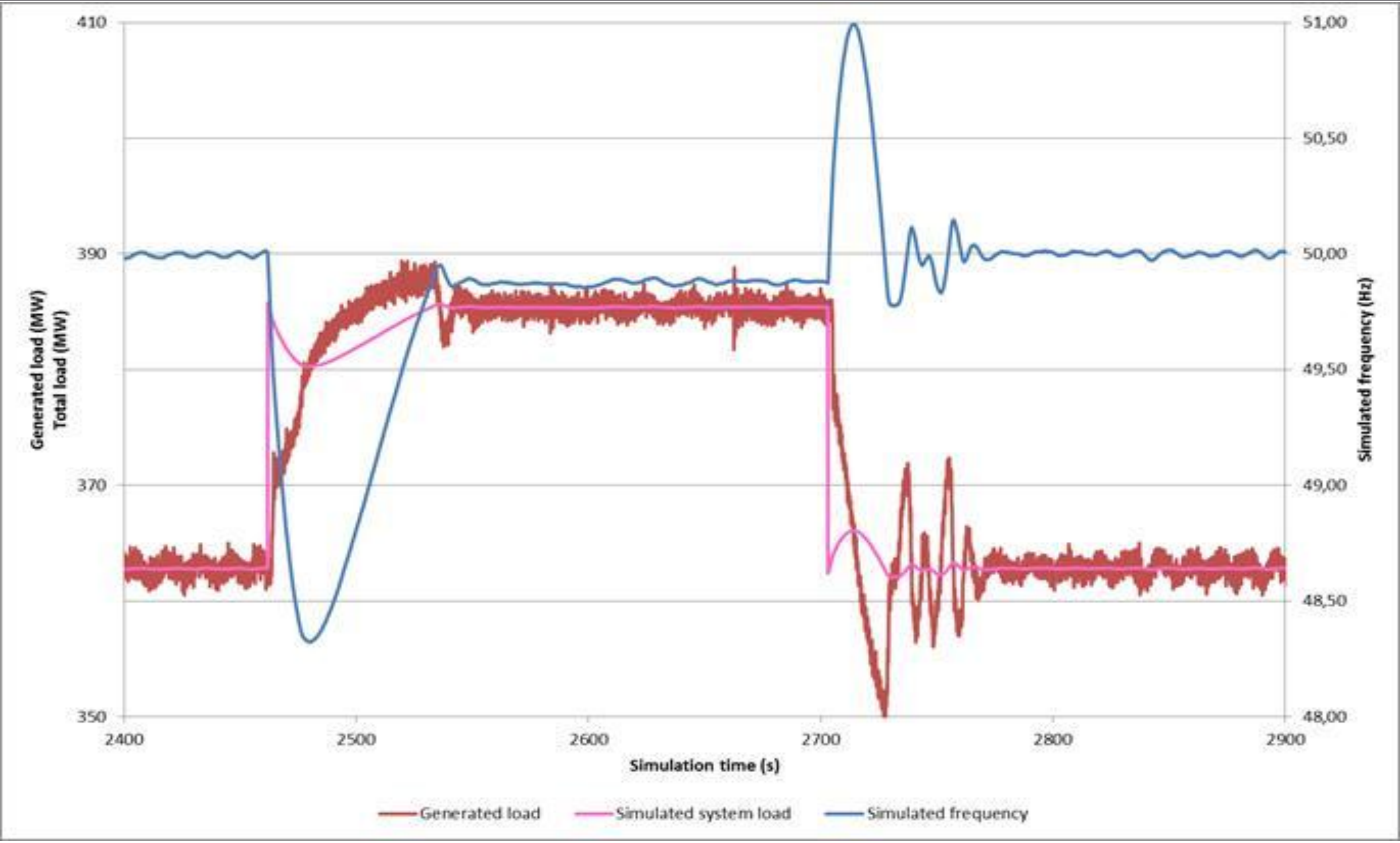


± 0.13 Hz step

Small island

- Governor response is reasonably stable, only small oscillations
- ± 5% limiter together with slow load control causes large frequency deviations
- Can handle at 20-25 MW load steps if steam conditions are good
- Again - difficult to keep steam pressure within limits
  - Overpressure OK
  - Underpressure – island grid collapses
- Plant is presently not fit for islanded operation

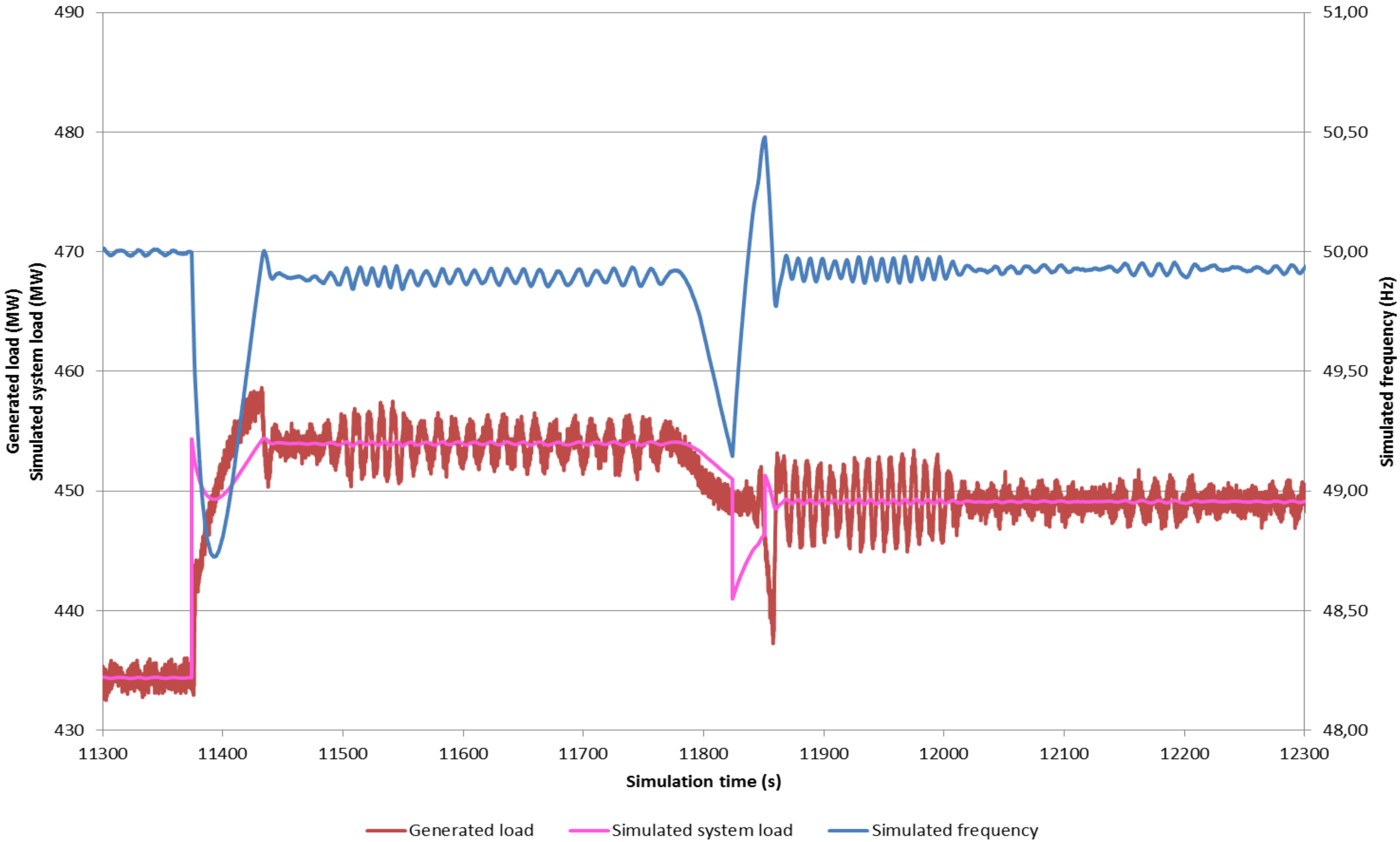
Small island 75 %



± 23 MW

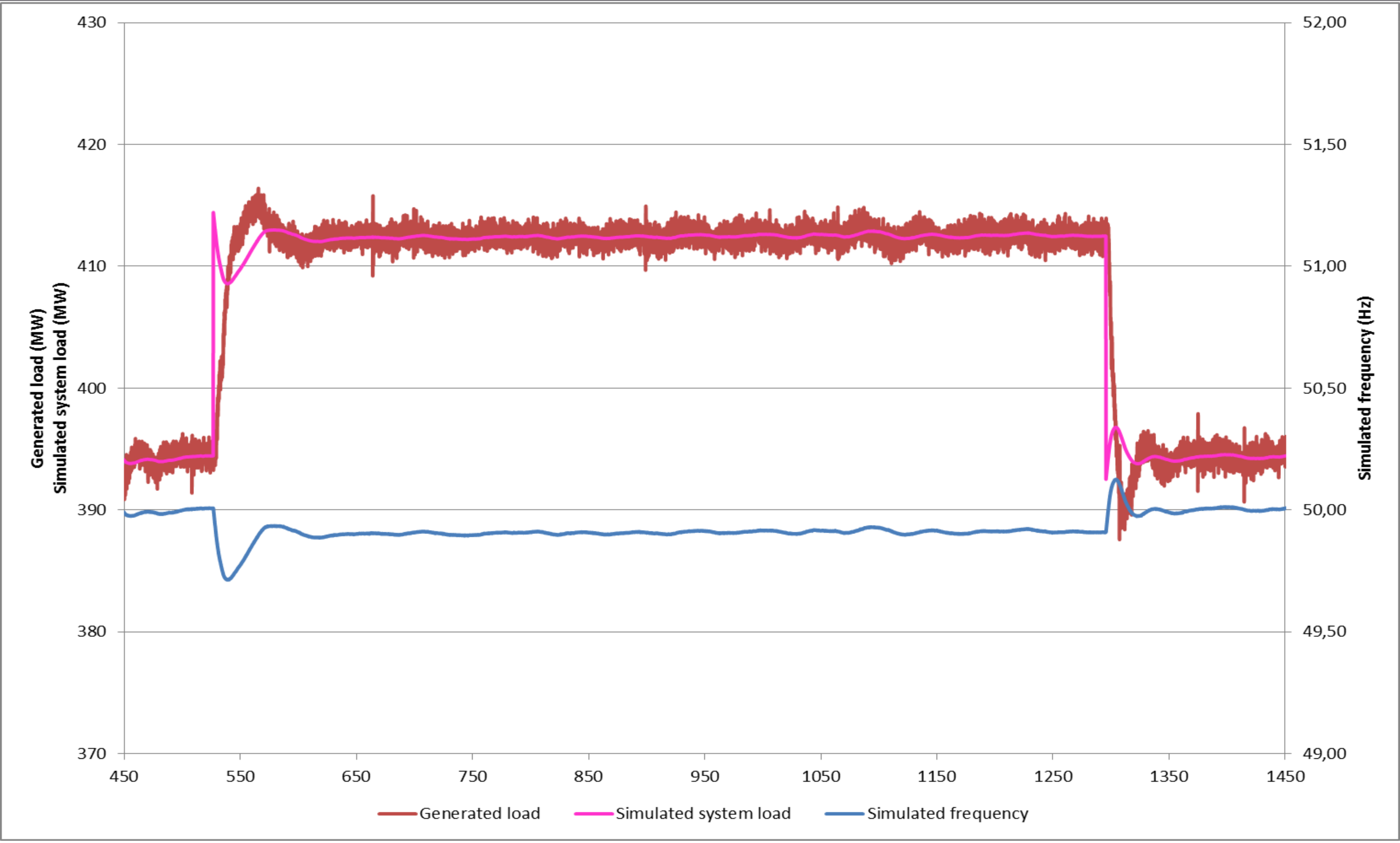
Solvina International

Small island 90 %



+ 20 MW

Large island 80 %



± 20 MW (although somewhat less on this unit)

Dadri I, unit 4, 210MW

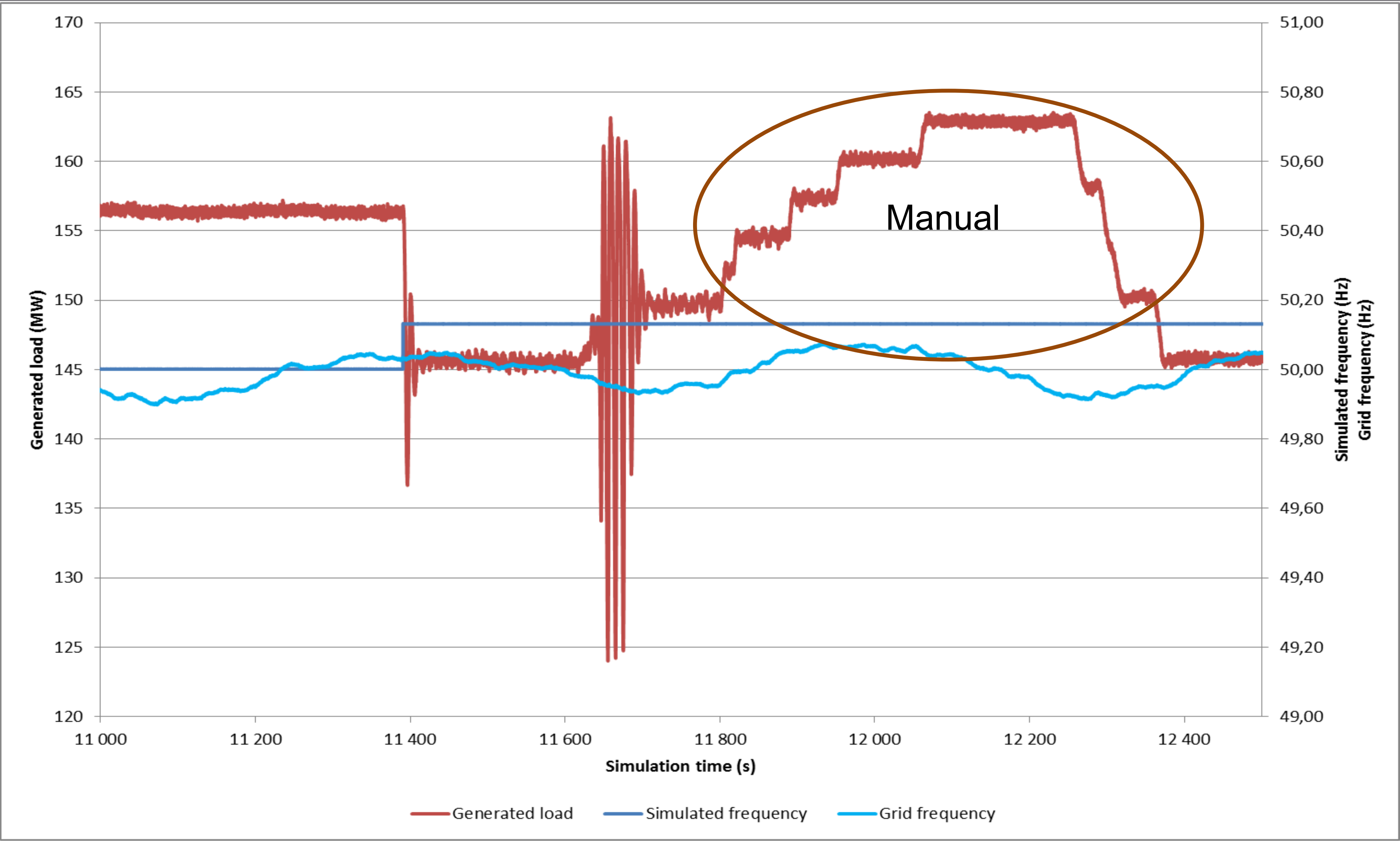
Step response tests

- Governor response OK:
  - Response as per droop
  - Response time 2-8 sec
- Difficult to keep steam pressure within limits
  - Overpressure – bypass opens
  - Underpressure – desired output not reached
  - Severe oscillations in certain conditions
- Plant is presently not fit for FGMO in interconnected operation

75% part 5

± 0.13 Hz step

75% part 4

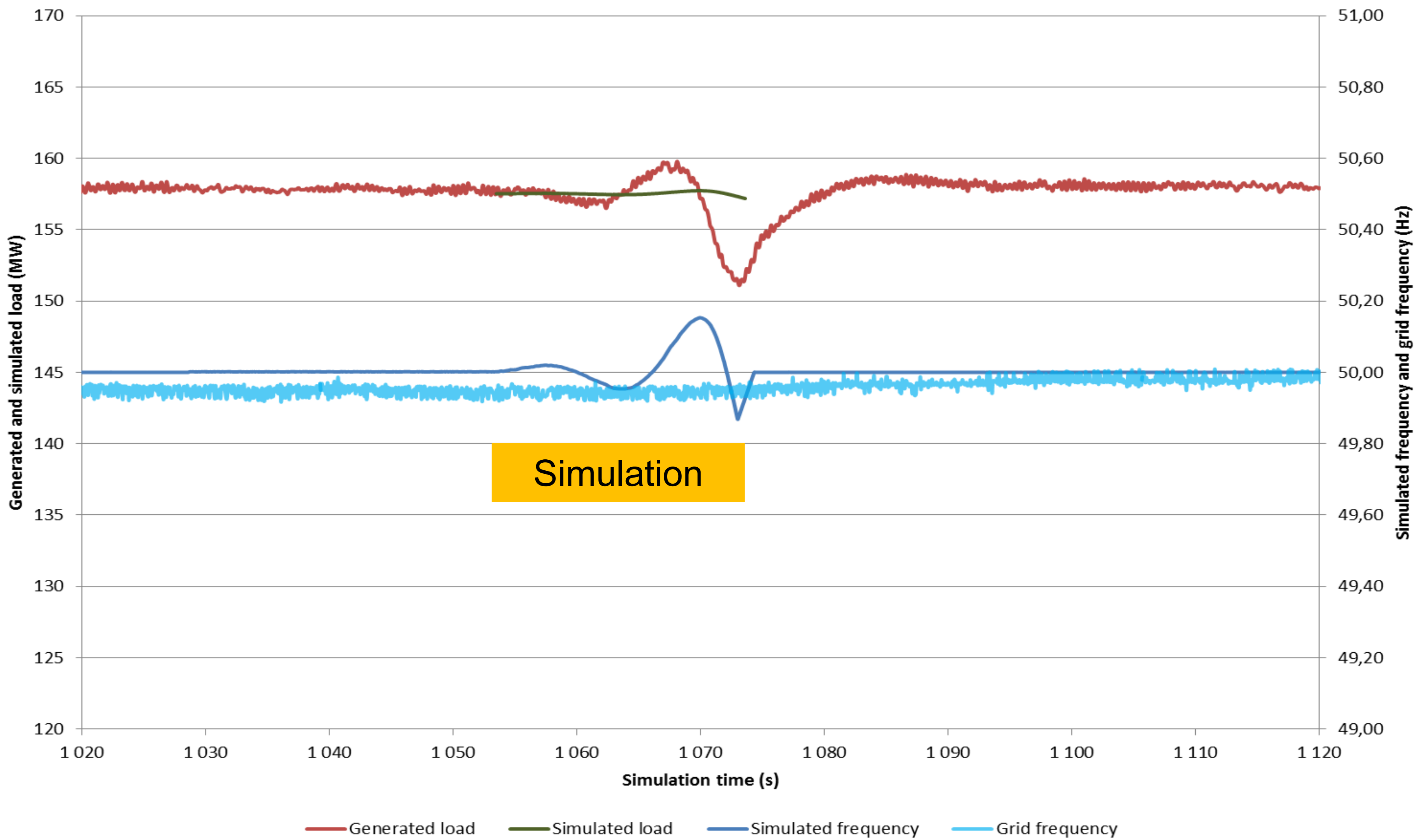


+ 0.13 Hz step

Small island

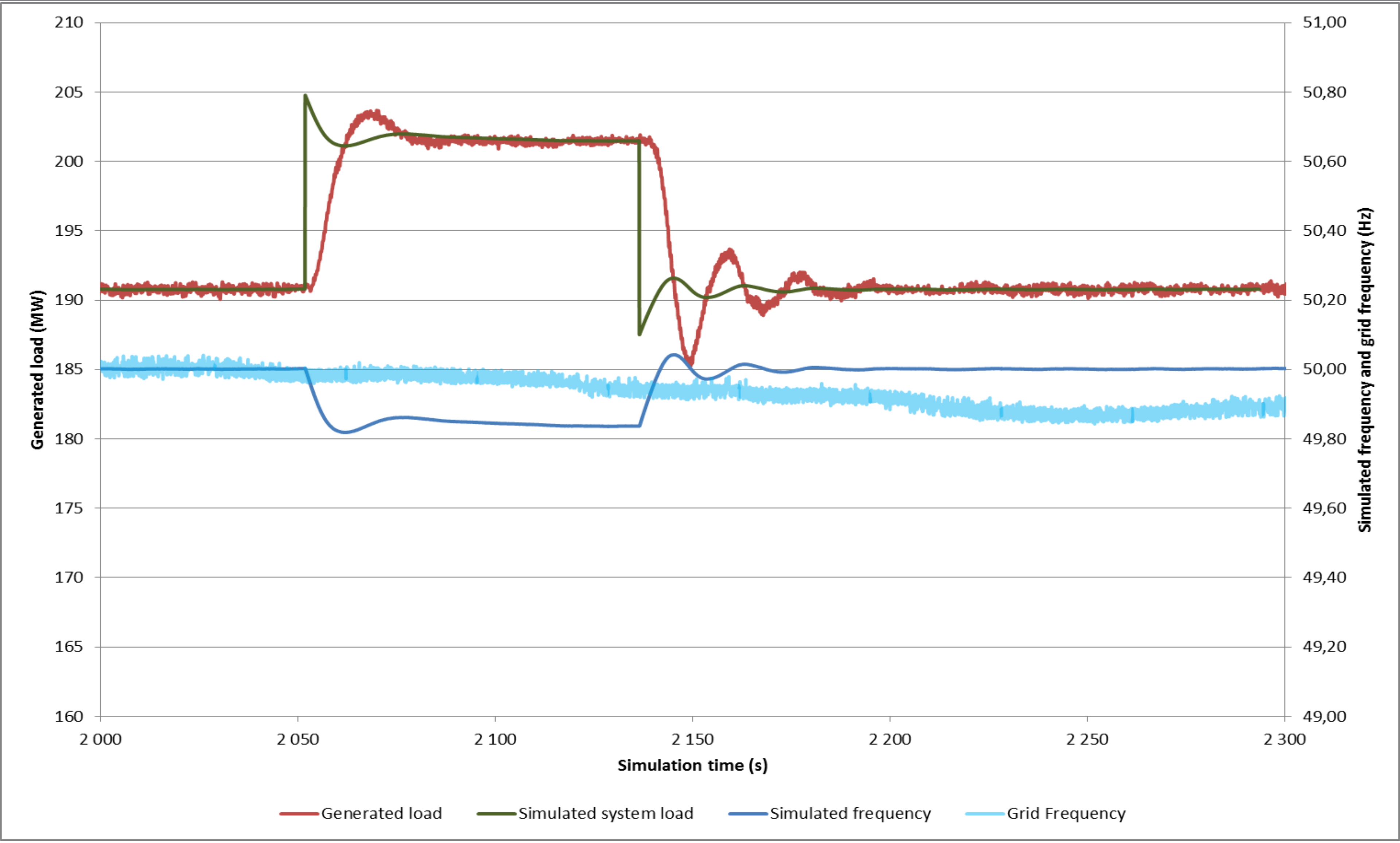
- Frequency control is unstable – oscillation starts immediately
- No load changes could be tested
- Plant is not fit for islanded operation

Small island 75 %



Solvina International

Large island 90 %



± 14 MW (although somewhat less on this unit)

Recommendations

Governor modification

- Load controller tuning needed at Dadri I, both to enable islanding and to manage steam conditions in interconnected operation without oscillations

- Also, in both Dadri I and Dadri II:
  - ± 5 % limit extended
  - Check controller windup in pressure/load ctrl.
  - Now: Grid freq. variation too large for droop
  - Not generated power feedback in islanding
  - Separate islanding mode?

Recommendations

Boiler control

Thermal plants (especially solid fuel) are difficult due to their complexity, but the following can be done to optimize the performance for primary response and Islanding…

- Feed forward for faster response
- Tuning to reduce oscillations

Recommendations

Handling

For island capability:

- Coordination with grid restoration essential
- Possibility to run with steam over-production? Excess steam bypassed to keep pressure stable.

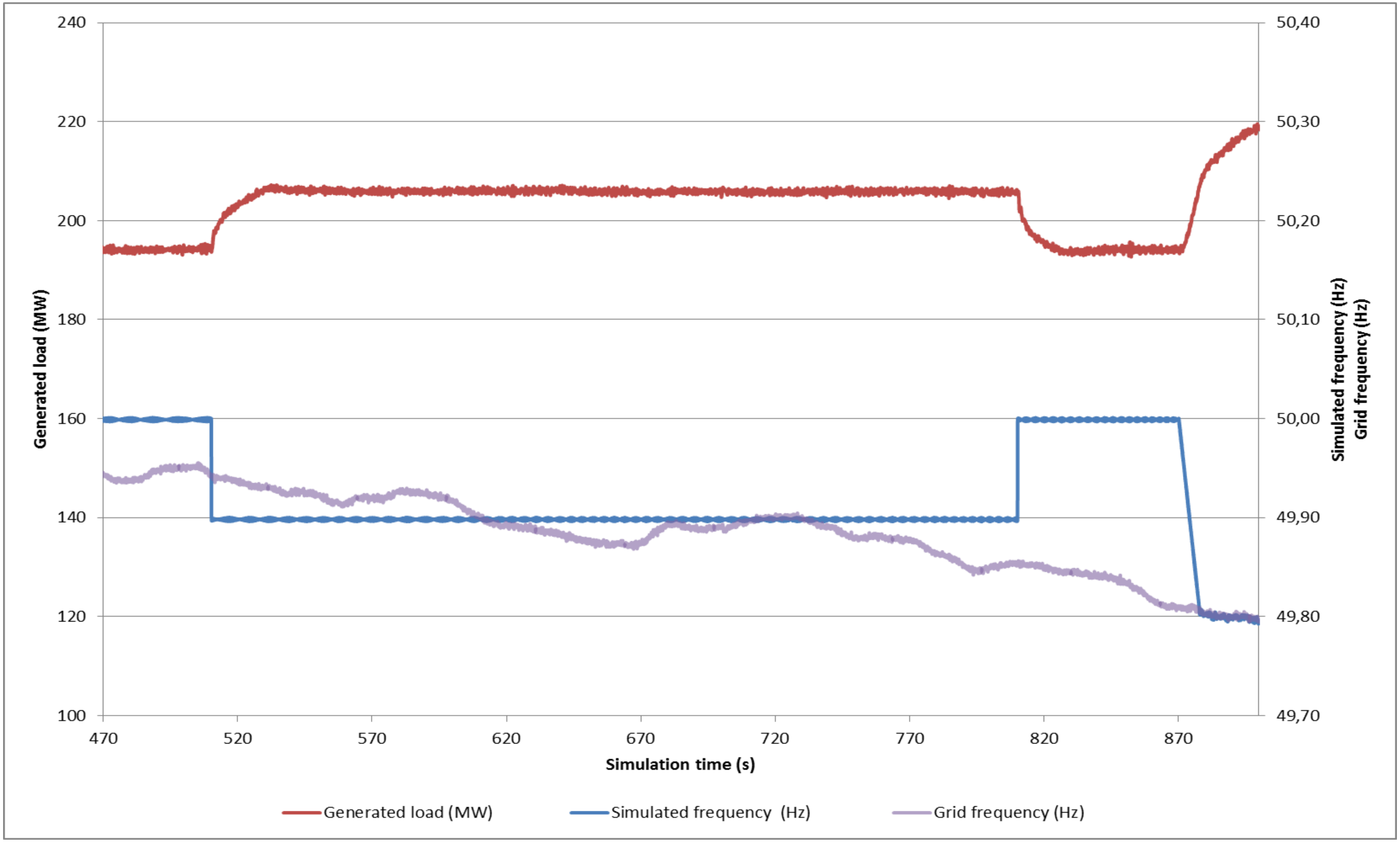
Bawana unit 2, 216MW

Step response tests

- Governor step response is good:
  - Response as per droop
  - Response time 3-10 sec

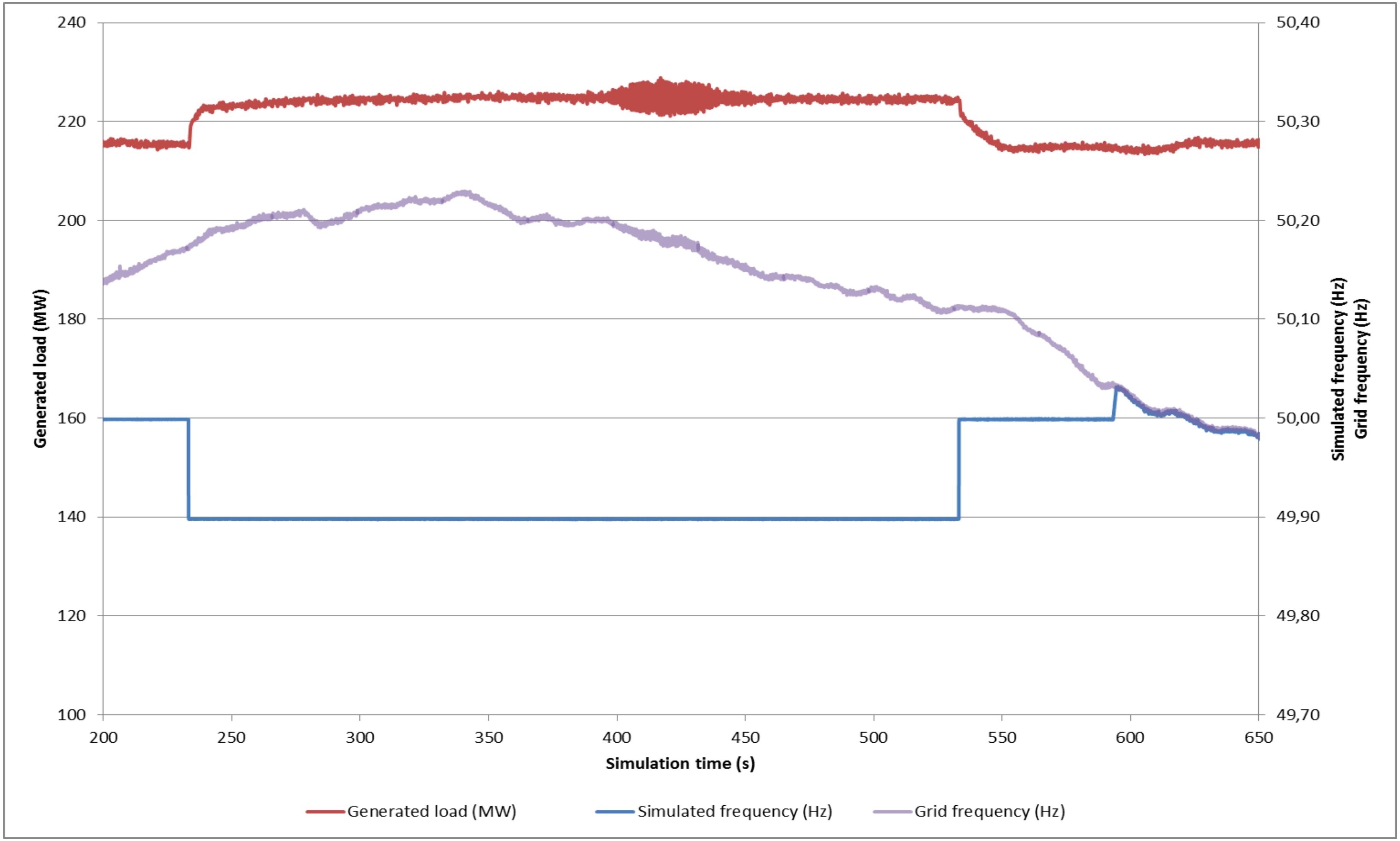
- Fast but yet stable behaviour, seems well tuned

90% part 1



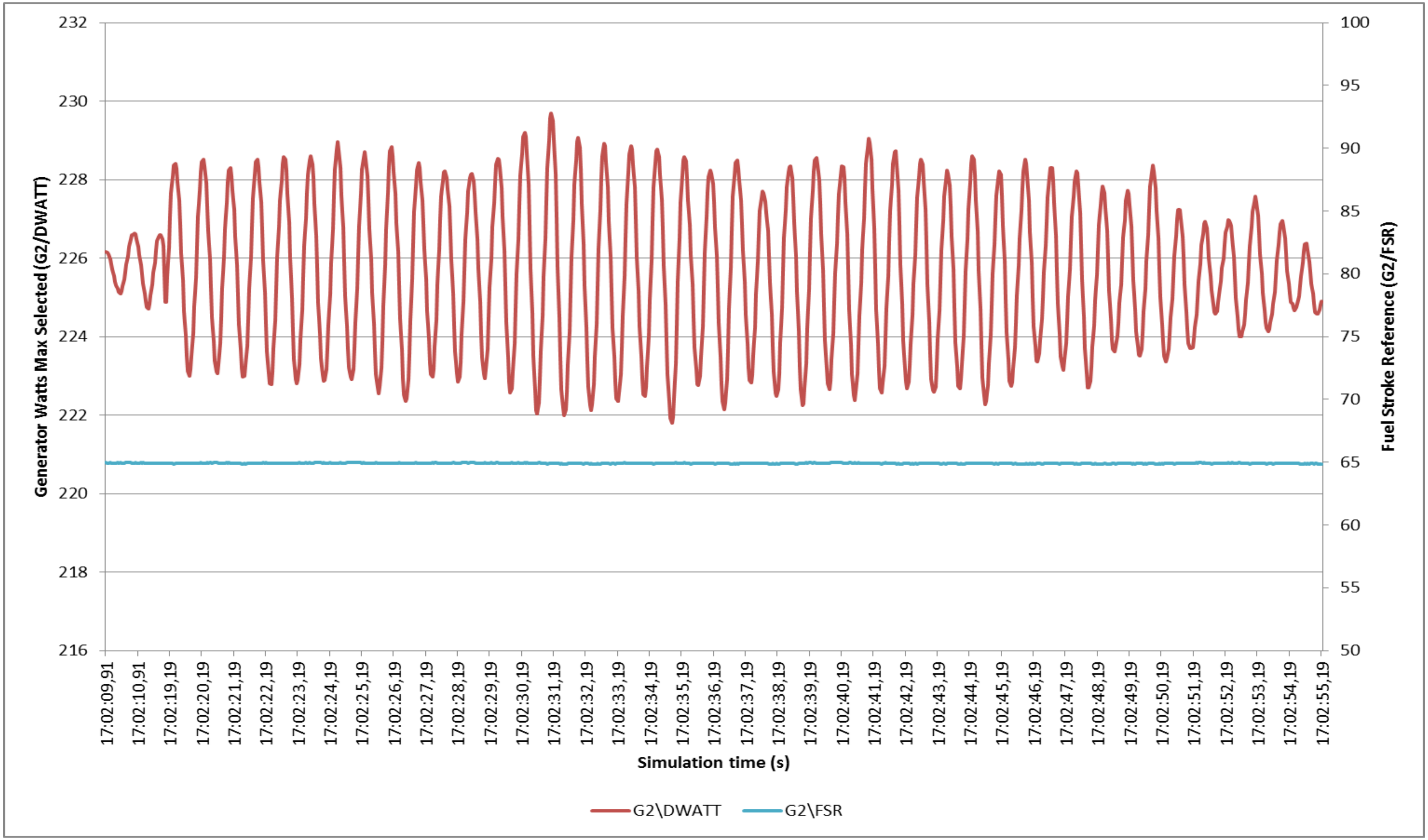
± 0.10 Hz step

100% part 1



+-0.10 Hz steps

100% part 1



+-0.10 Hz steps

Recommendations

The tests that could be carried out, with open loop changes, showed a good behavior.

No recommendations for the plant frequency control is motivated from these tests.

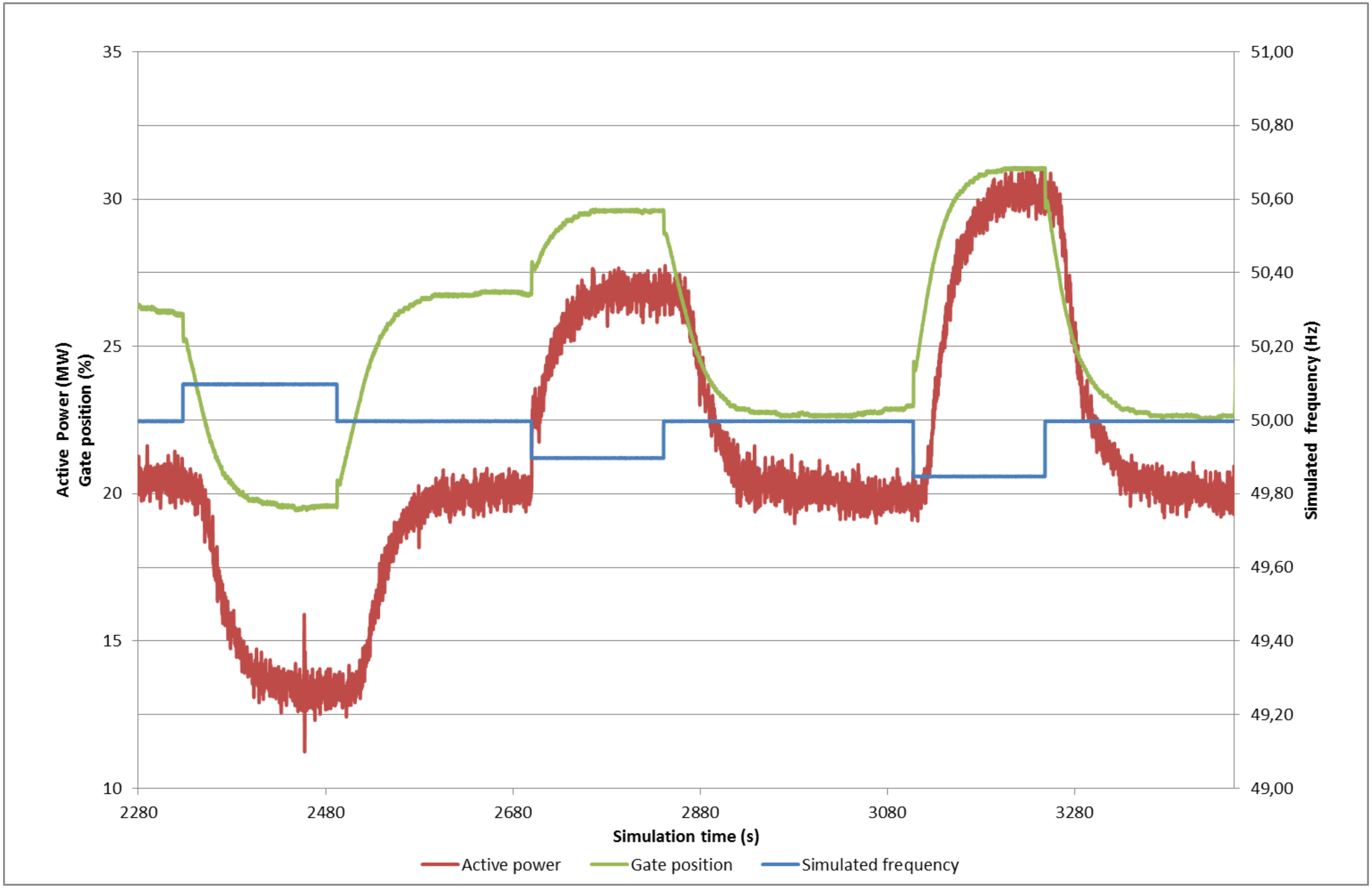
It might be motivated with a review of the PSS settings, due to the oscillations observed.

Chamera I, unit 3, 180MW

Step response

- **FGMO, power feedback ON**
- Responds consistently and according to droop.
- Response time varies depending on previous changes due to mechanical backlash.

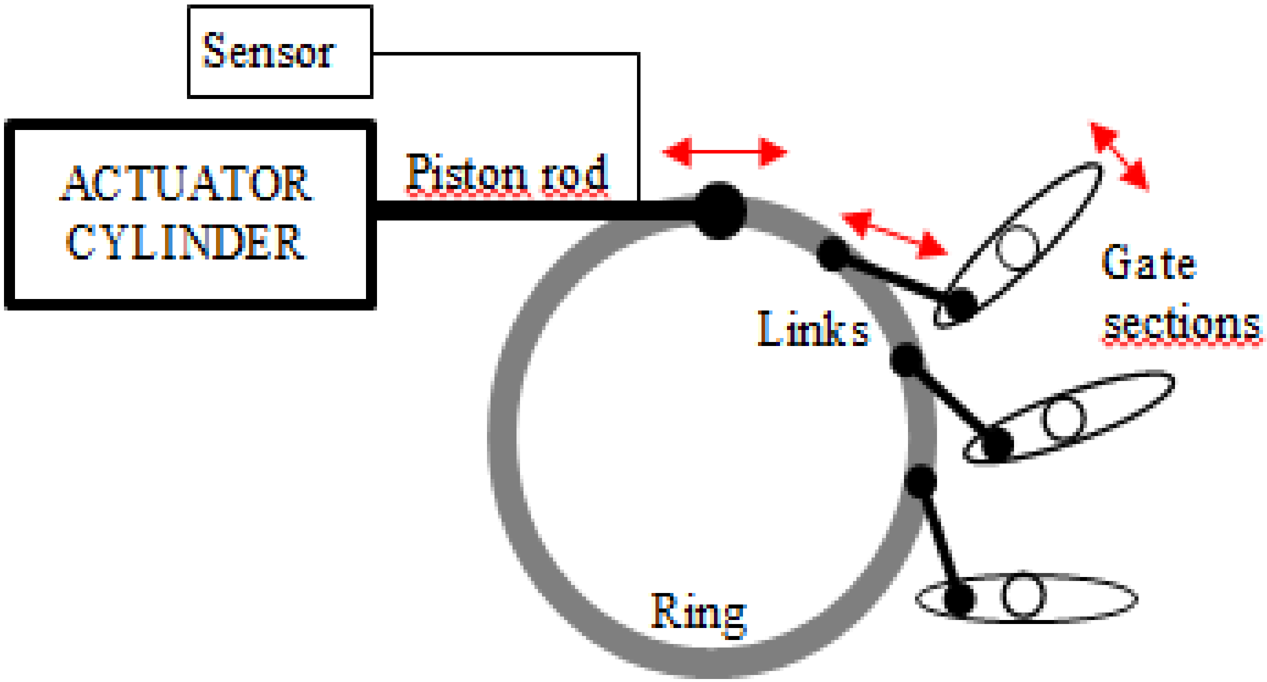
FGMO



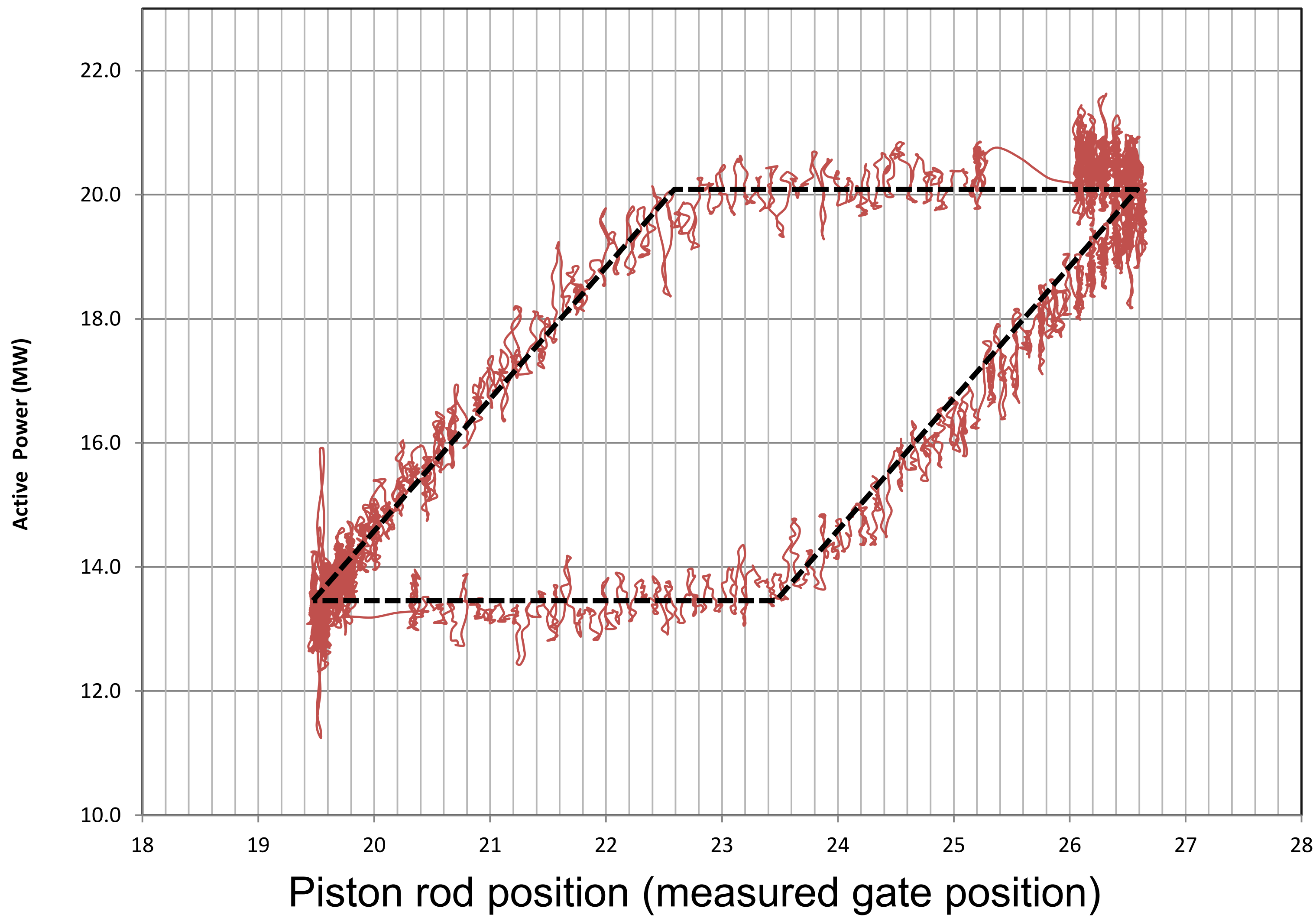
35
30
25
20
15
10
51,00
50,80
50,60
50,40
50,20
50,00
49,80
49,60
49,40
49,20
49,00
2280
2480
2680
2880
3080
3280
Active Power (MW)
Gate position (%)
Simulated frequency (Hz)
Simulation time (s)
Active power
Gate position
Simulated frequency

PF On

Background: Actuator



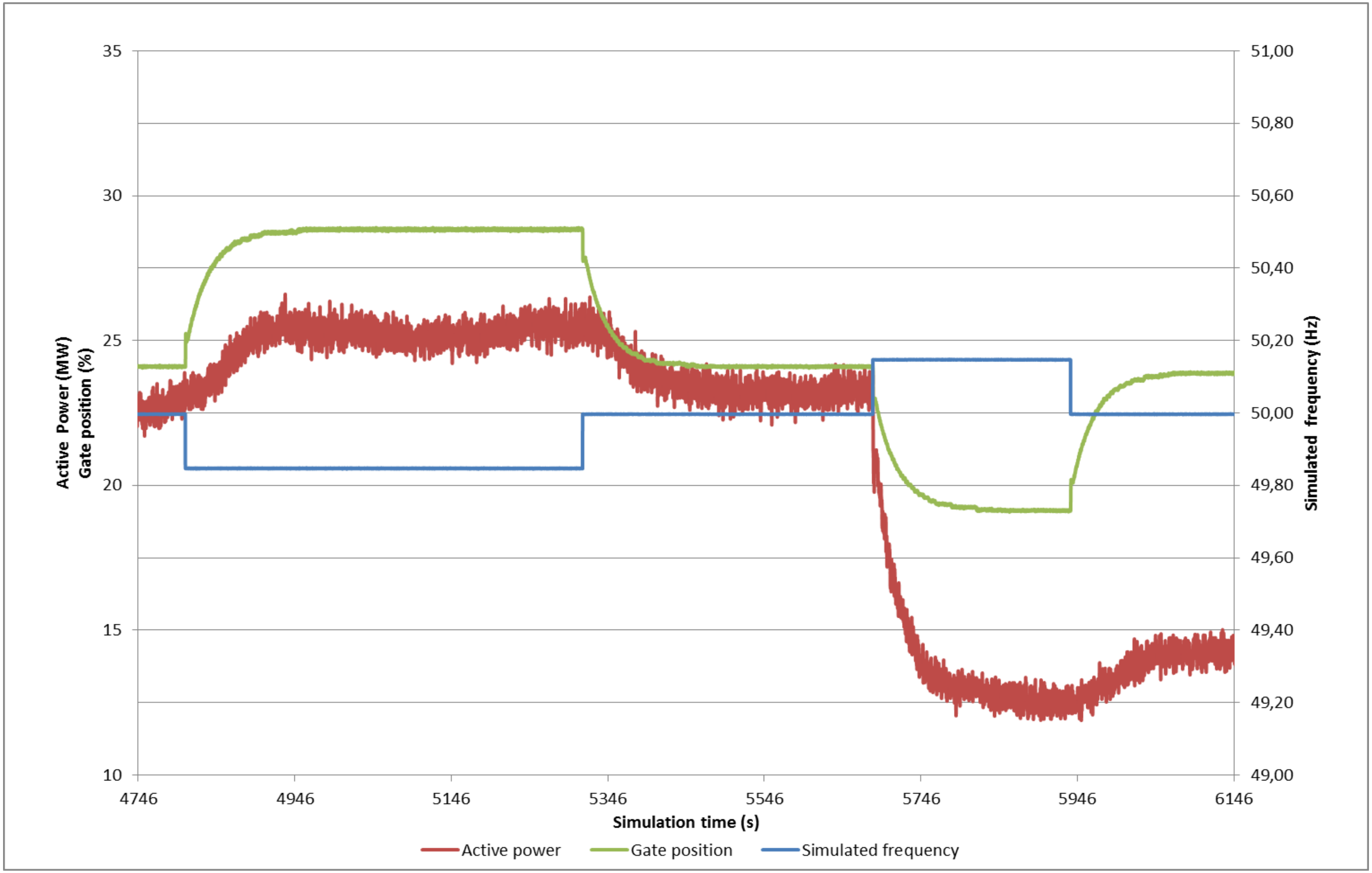
Mechanical backlash - Hysteresis



Step response cont.

- **FGMO, power feedback OFF:**
- Gate position responds consistently and according to droop
- Output response magnitude and time varies depending on previous changes due to mechanical backlash.

FGMO


35
30
25
20
15
10
51,00
50,80
50,60
50,40
50,20
50,00
49,80
49,60
49,40
49,20
49,00
Active Power (MW)
Gate position (%)
Simulated frequency (Hz)
4746
4946
5146
5346
5546
5746
5946
6146
Simulation time (s)
Active power
Gate position
Simulated frequency

PF Off

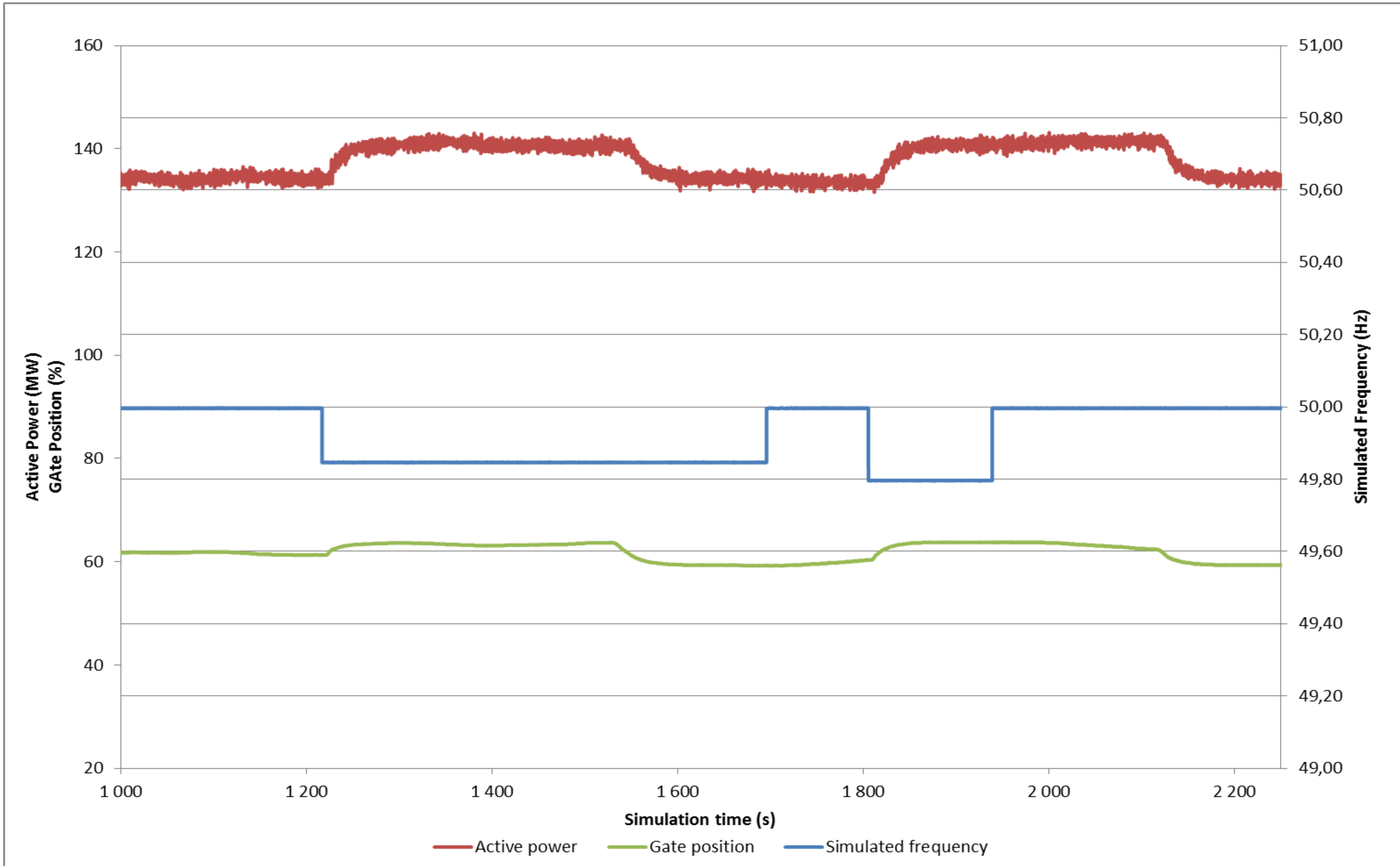
Step response cont.

RGMO

- Expected response seen consistently: Frequency drop
  -> output immediately up 5 % of actual for 5 minutes, then returning to original output.

- Frequency above RGMO band – response according to droop

RGMO



160
140
120
100
80
60
40
20
51,00
50,80
50,60
50,40
50,20
50,00
49,80
49,60
49,40
49,20
49,00
Active Power (MW)
GAte Position (%)
Simulated Frequency (Hz)
1 000
1 200
1 400
1 600
1 800
2 000
2 200
Simulation time (s)
Active power
Gate position
Simulated frequency

Small island

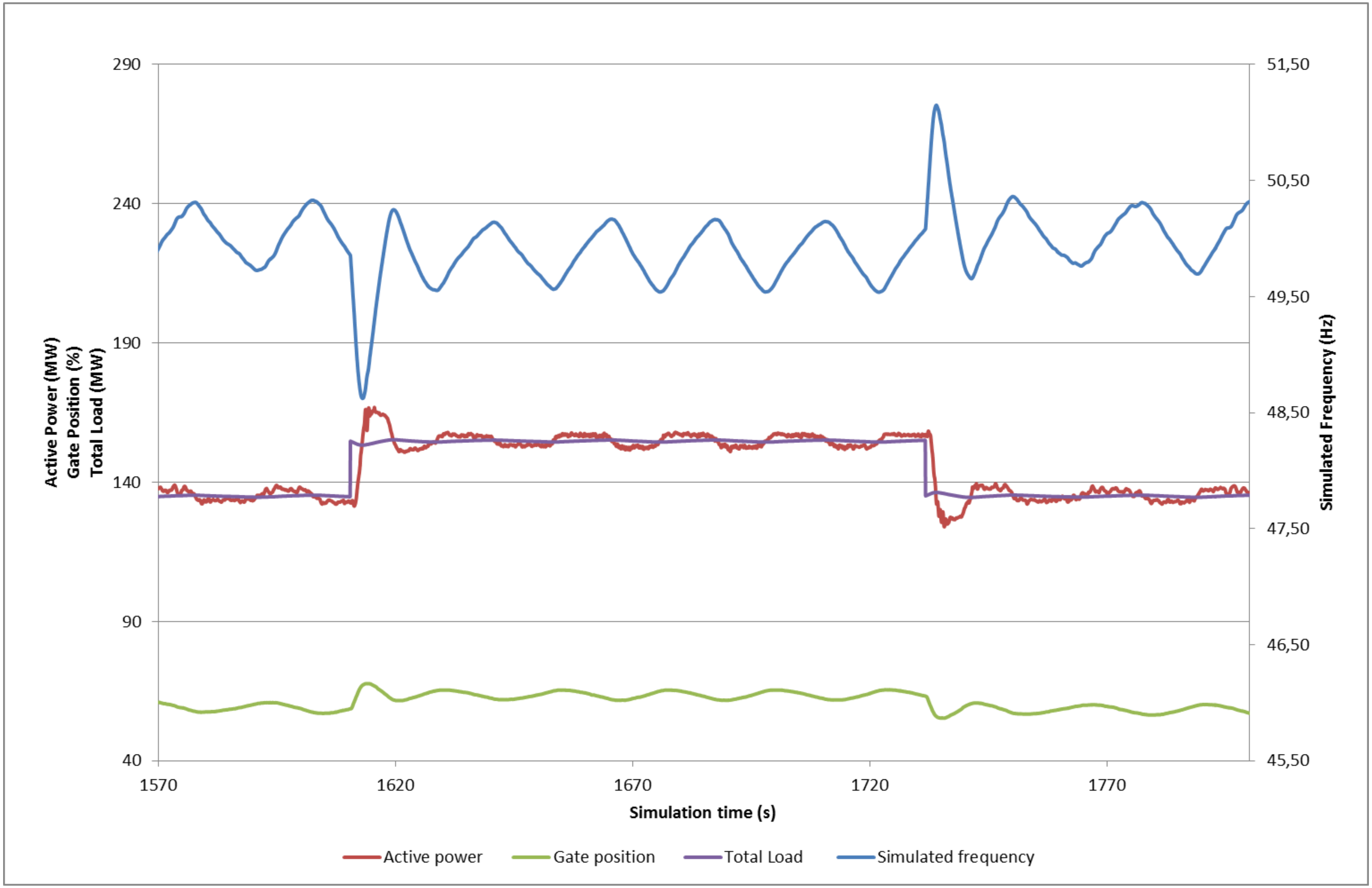
- Generally behaves well considering type of power plant. Handles load steps very well.

- Continuous slow oscillation due to actuator backlash, this is not unusual.

- Can handle at least ±20 MW at 10-75 % load.

- Effect of water dynamics insignificant.

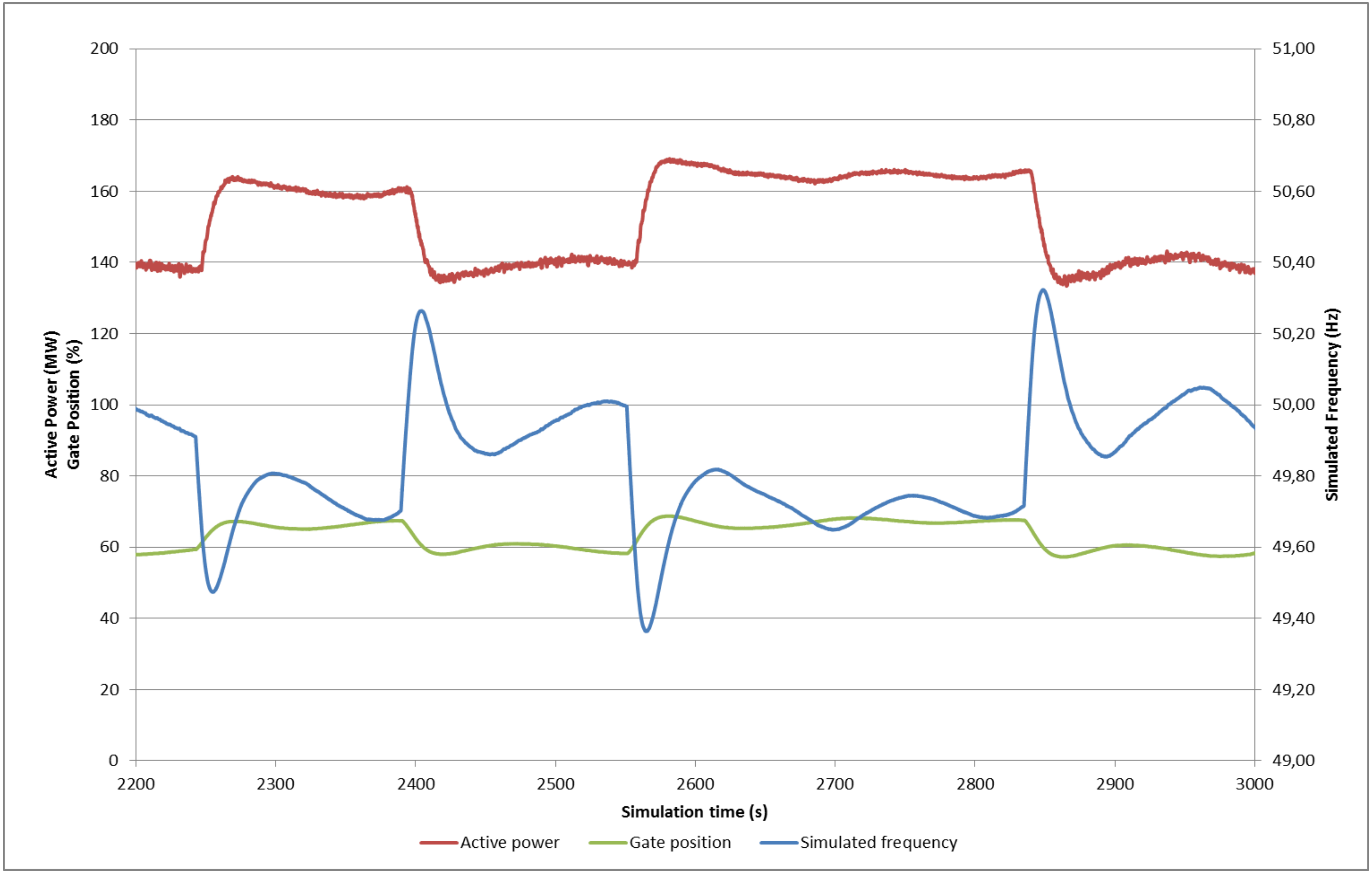
Small island



±20 MW @ 75 % load

Solvina International

Large island



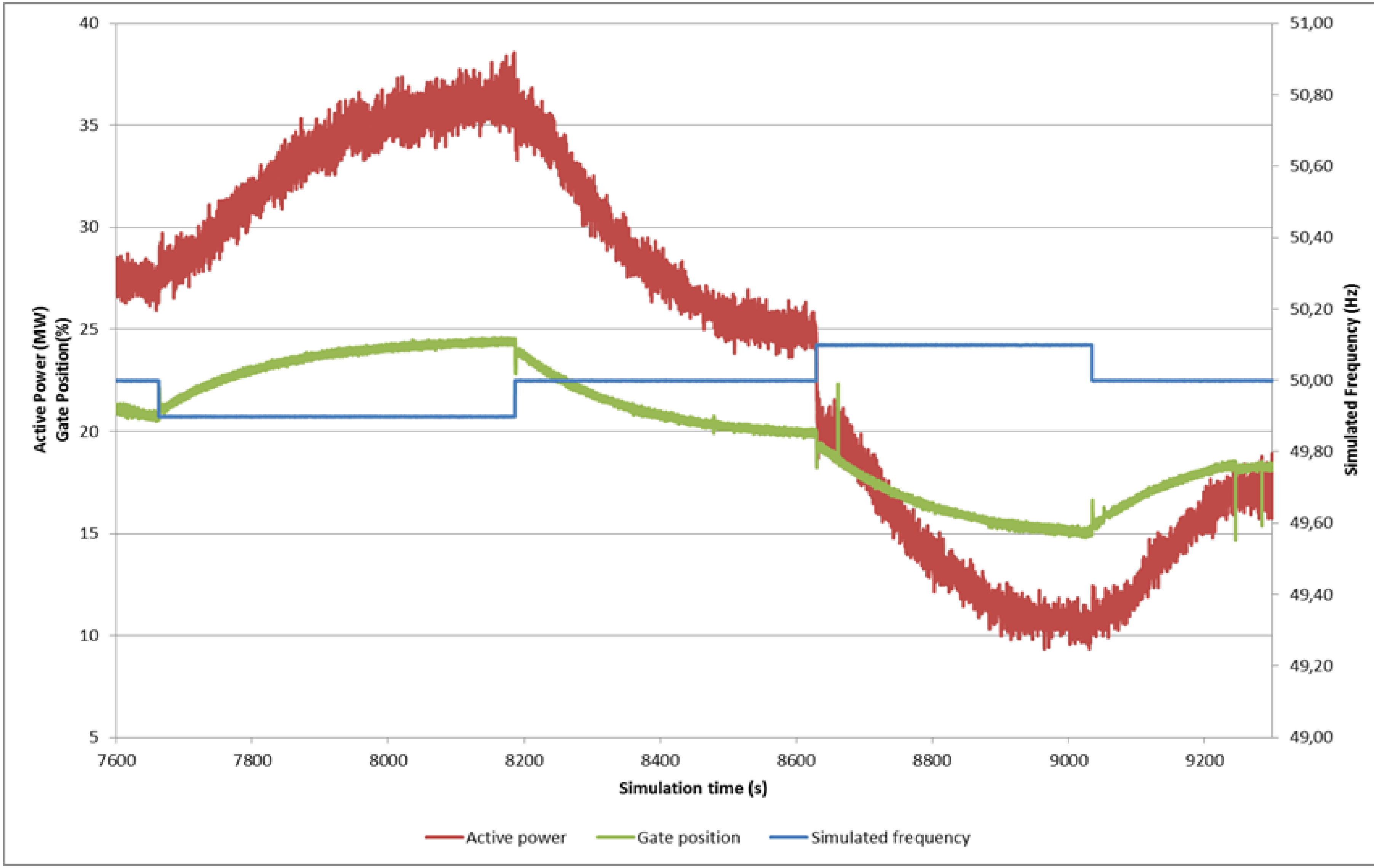
± 25, ±30 MW (although somewhat less on this unit)

Tehri unit 2, 250MW

Step response

- There is no FGMO mode where the load setpoint can be given.
- “Frequency mode”, intended for black start and islanding, was tested with regard to Frequency response.
- “Frequency mode” works as expected and responds well to frequency changes.
- Output change referred to gate opening, actual load not following exactly.

Frequency mode

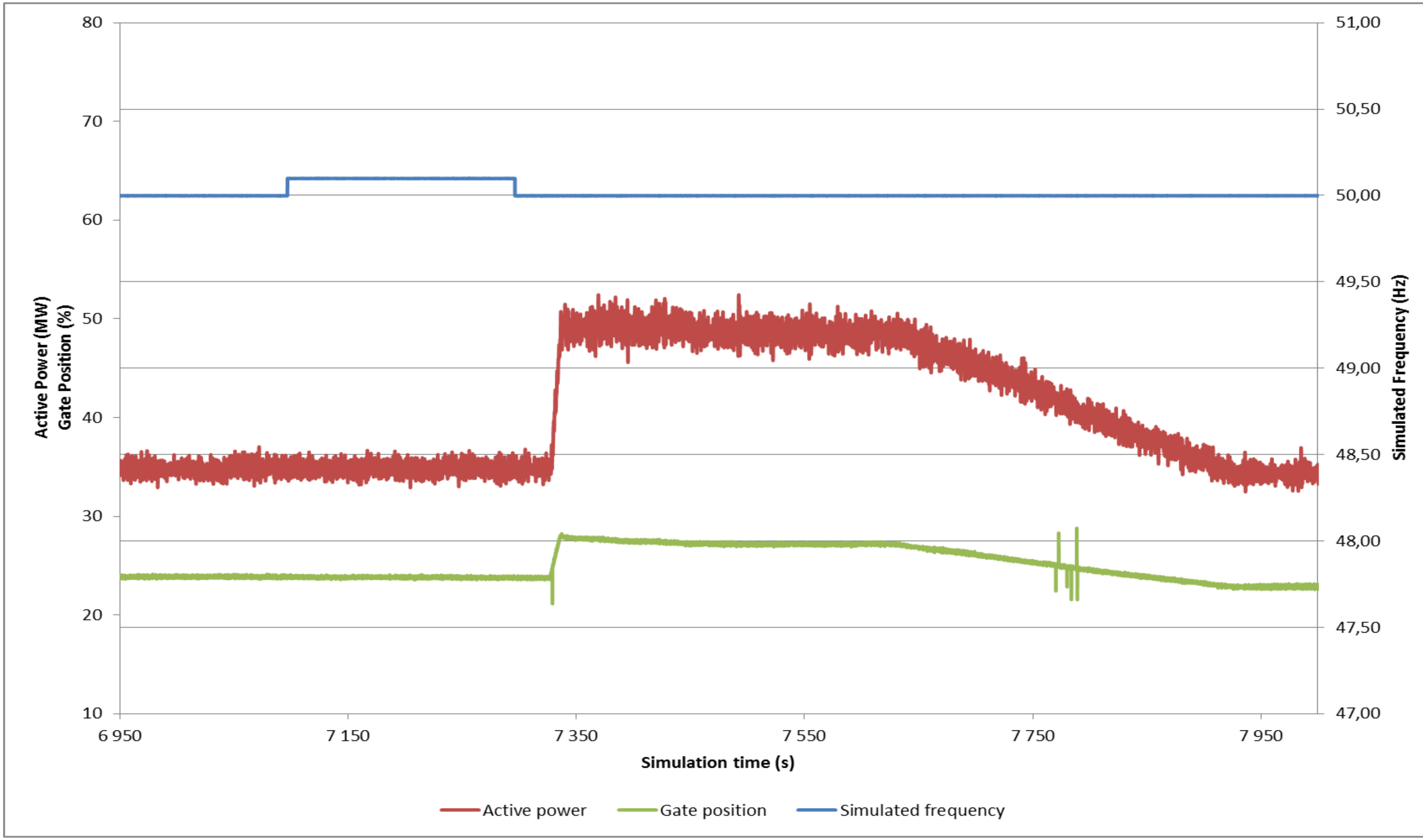


Solvina International

RGMO

- RGMO works in accordance with grid code in most cases, but also inconsistently in some situations.
- Power mode has some frequency response but it is insignificant

RGMO – normal response



Step response

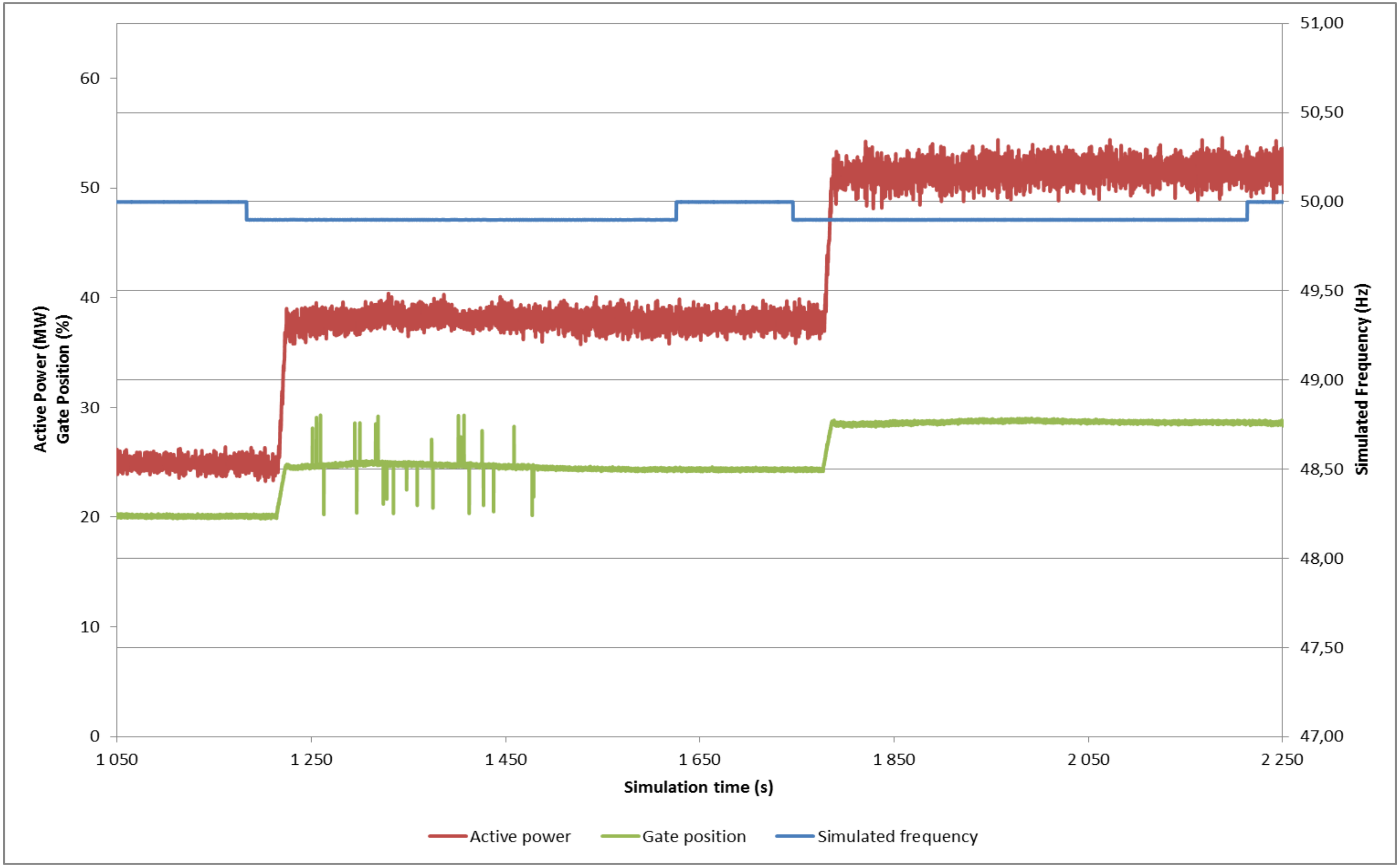
RGMO

- However, irregular behaviour also seen
  - No ramping back
  - Sudden output increase

- May be related to test method but not entirely.

- Also seen in long time recording when frequency exceeds RGMO band

RGMO – irregular response



RGMO Difference Chamera and Tehri

The main differences in interpretations are:

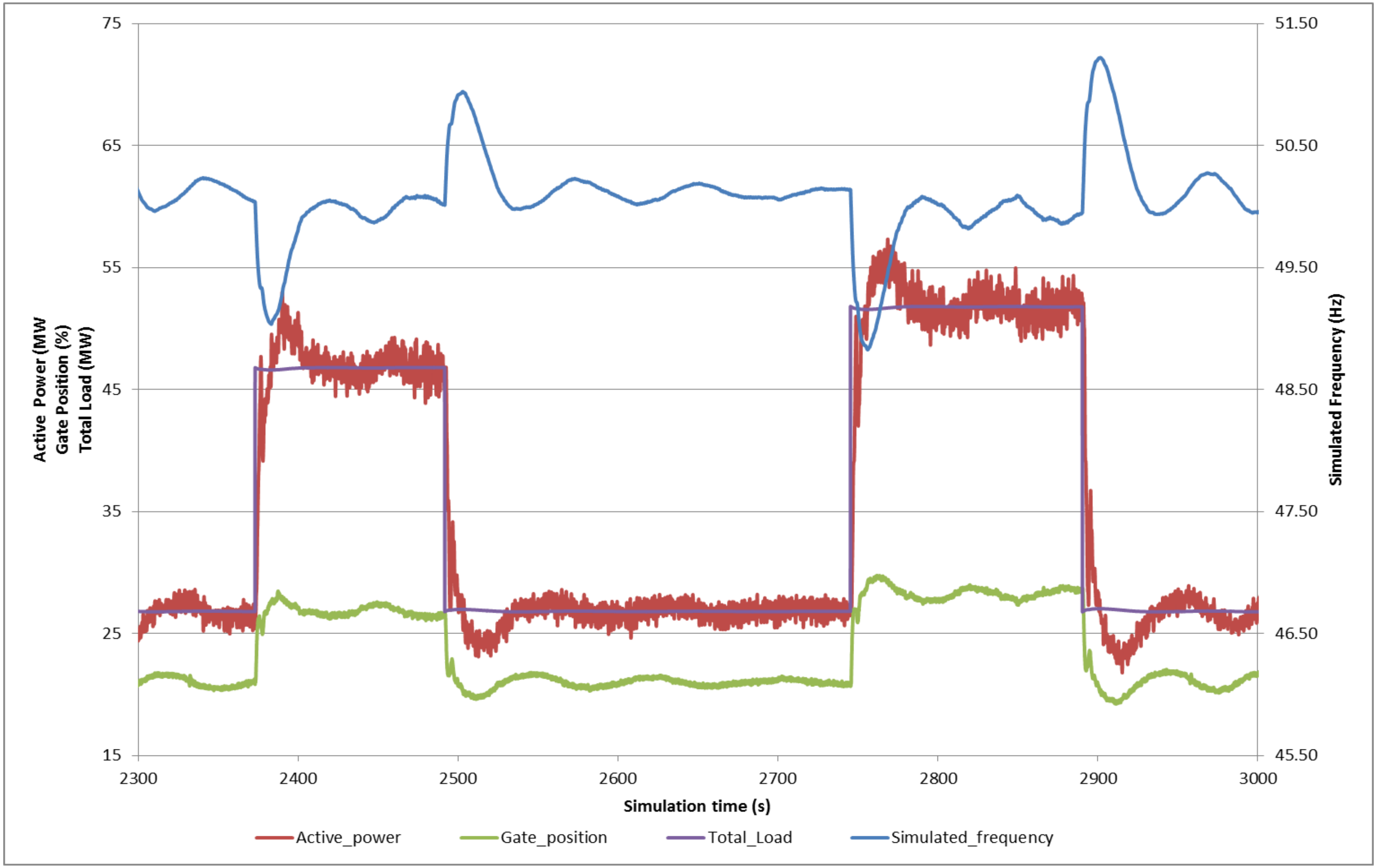
- The response magnitude is 5 % of actual output at Chamera and 5 % of rated output at Tehri.
- The response is immediate at Chamera but comes after 30 seconds at Tehri.
- After 5 minutes, the power ramps back quickly at Chamera and over a time of 5 minutes at Tehri.

Small island

- Generally behaves well considering type of power plant.
- Continuous slow oscillation due to actuator backlash (although small at 10 % load), this is not unusual.
- Can handle at least ±25 MW at 10 % load.
- Can handle ±12 MW at 90 % load.
  Effect of water dynamics seen clearly.

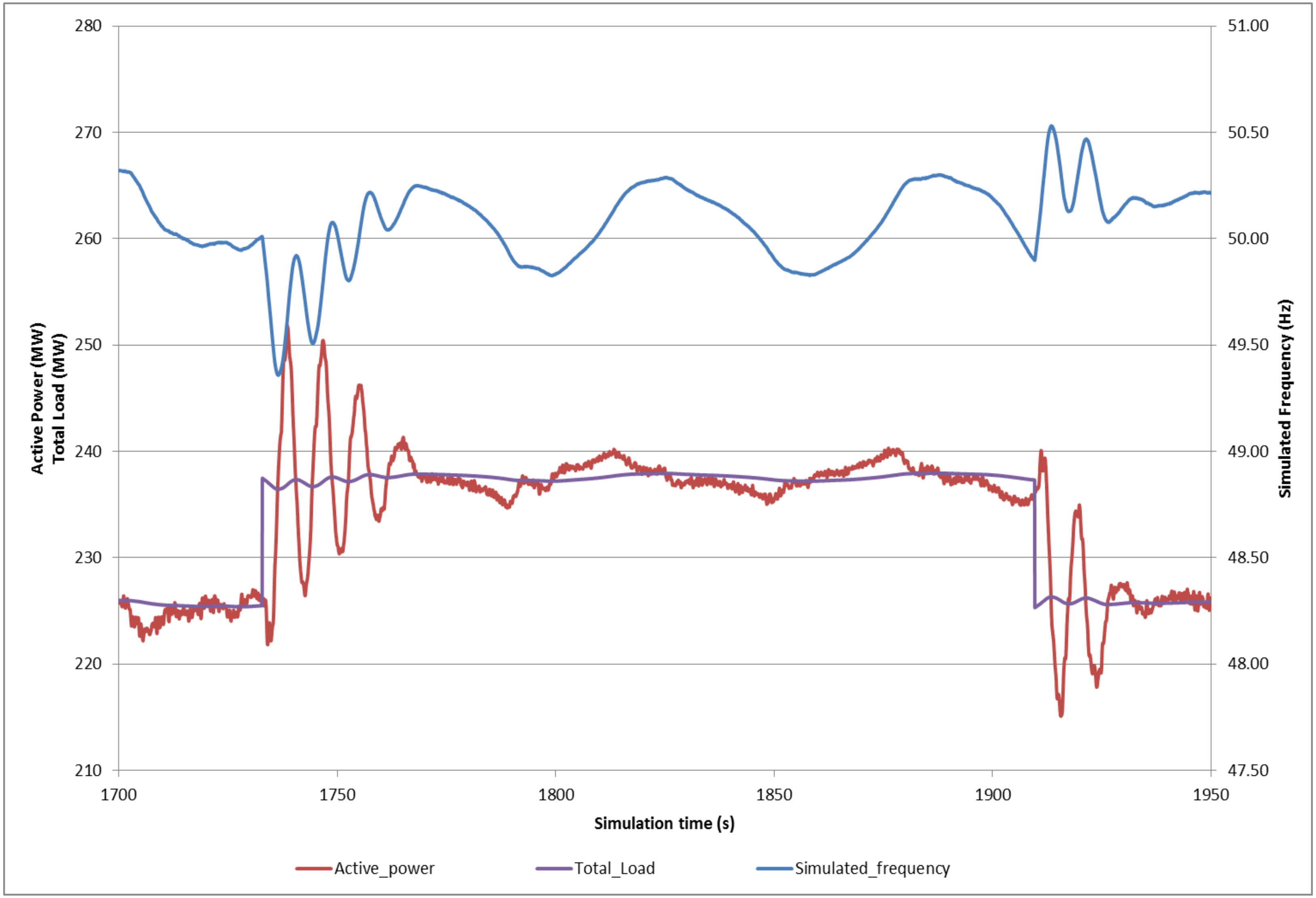
Solvina International

Small island



± 20, ±25 MW @ 10 % load

Small island

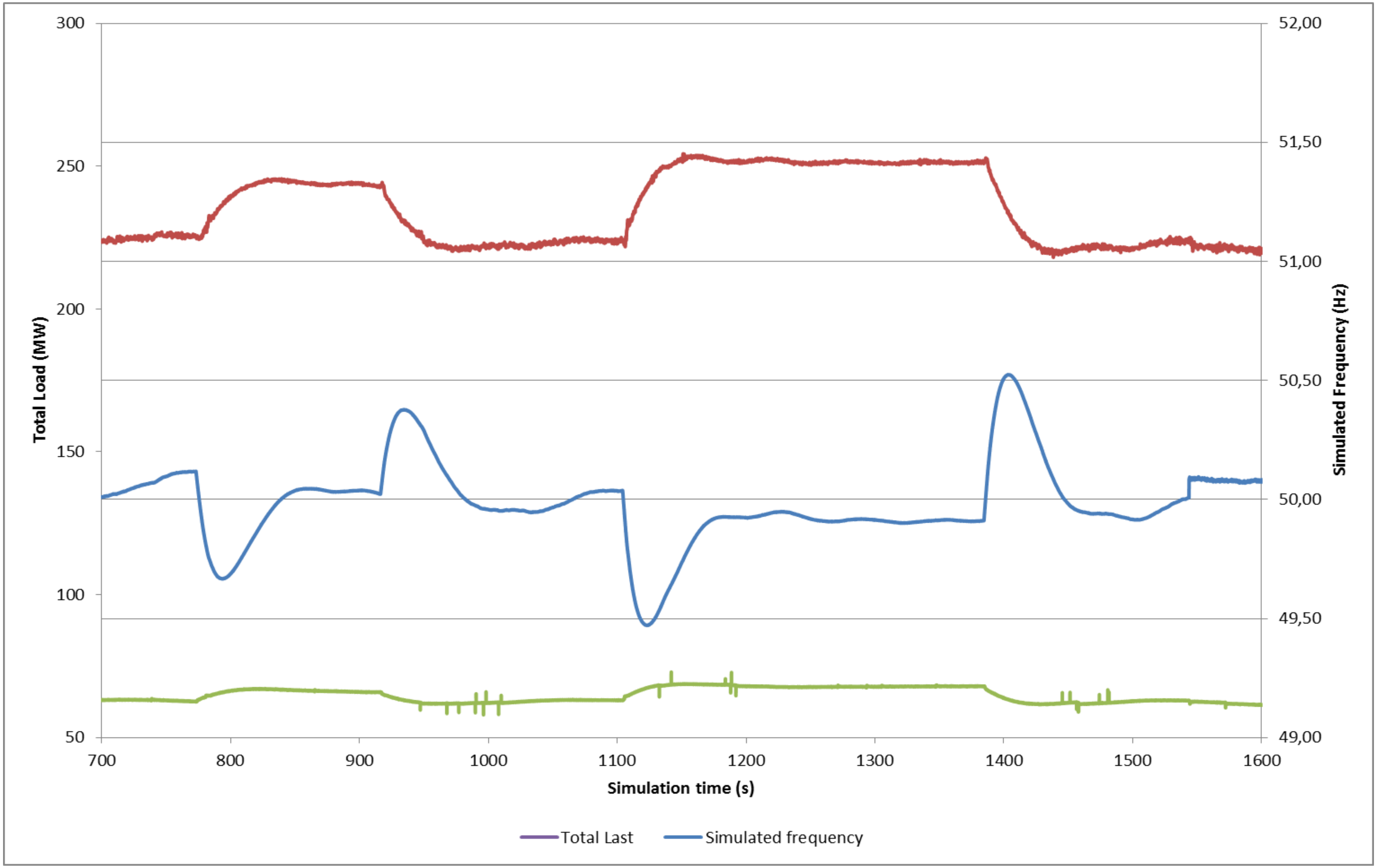


±12 MW @ 90 % load

Large island

- The ability of the unit to control the frequency together with other power plants on an island grid is also very good.

Large island



± 20, ±30 MW (although somewhat less on this unit)

Recommendations general

- FGMO operation conclusions
  - use power feedback **on** in normal operation
  - use power feedback **off** when islanding (for stability reasons)
- Parameter settings good in both units
- RGMO –
  - Dadri, no recommendation needed
  - Tehri governor requires an overview
- Less mechanical backlash would be beneficial

Recommendations

- FGMO implementation necessary in Tehri
  - Frequency mode structure can be used with some additions (power setpoint)
  - Parameter settings OK
    (integrator time could be faster)
- For correct function it is also important that units are operated in the right control mode.

Test conclusions and recommendations

Energy Excellence

General comments

Hydro power plants

- Generally well suited for frequency control, incl. islanding.
- Response is practically only limited by turbine rating.
- Only Francis tested, Kaplan and Pelton differ

Thermal Power Plants (boilers)

- Can provide initial fast response
- Thermal process is complex and slow, which requires special attention.

Gas Turbines

- Can respond very quickly
- Ideal both for fast primary response and for islanding.

FGMO / RGMO

- FGMO and RGMO are NOT internationally used terms.

- FGMO and RGMO seems to have different interpretations in India

RGMO comments

RGMO is implemented as per the Grid Code in both Chamera and Tehri but the interpretations are different. Hence, the Grid Code is not completely clear.

RGMO is not acting in proportion to the frequency deviation and is NOT strictly a frequency governing mode, rather a logic to increase the generated load at frequency drops.

RGMO is missing controller feedback and consequently, no stable dynamic equilibrium can be reached with this mode.

FGMO comments

- FGMO is not an internationally used expression
- FGMO seems to have different interpretations in India.
- A combined Frequency and Load Control is commonly used internationally, and could be found in Dadri and Chamera for instance.
- Referred to as **Frequency Control with Droop**
- All generation types need to be considered for primary control, but can be utilized a bit differently given the basic conditions.

On Frequency Dynamics

Primary control – intends to maintain the power balance in the system and hence keep the frequency reasonably close to 50Hz.

Should be automatic and always present.

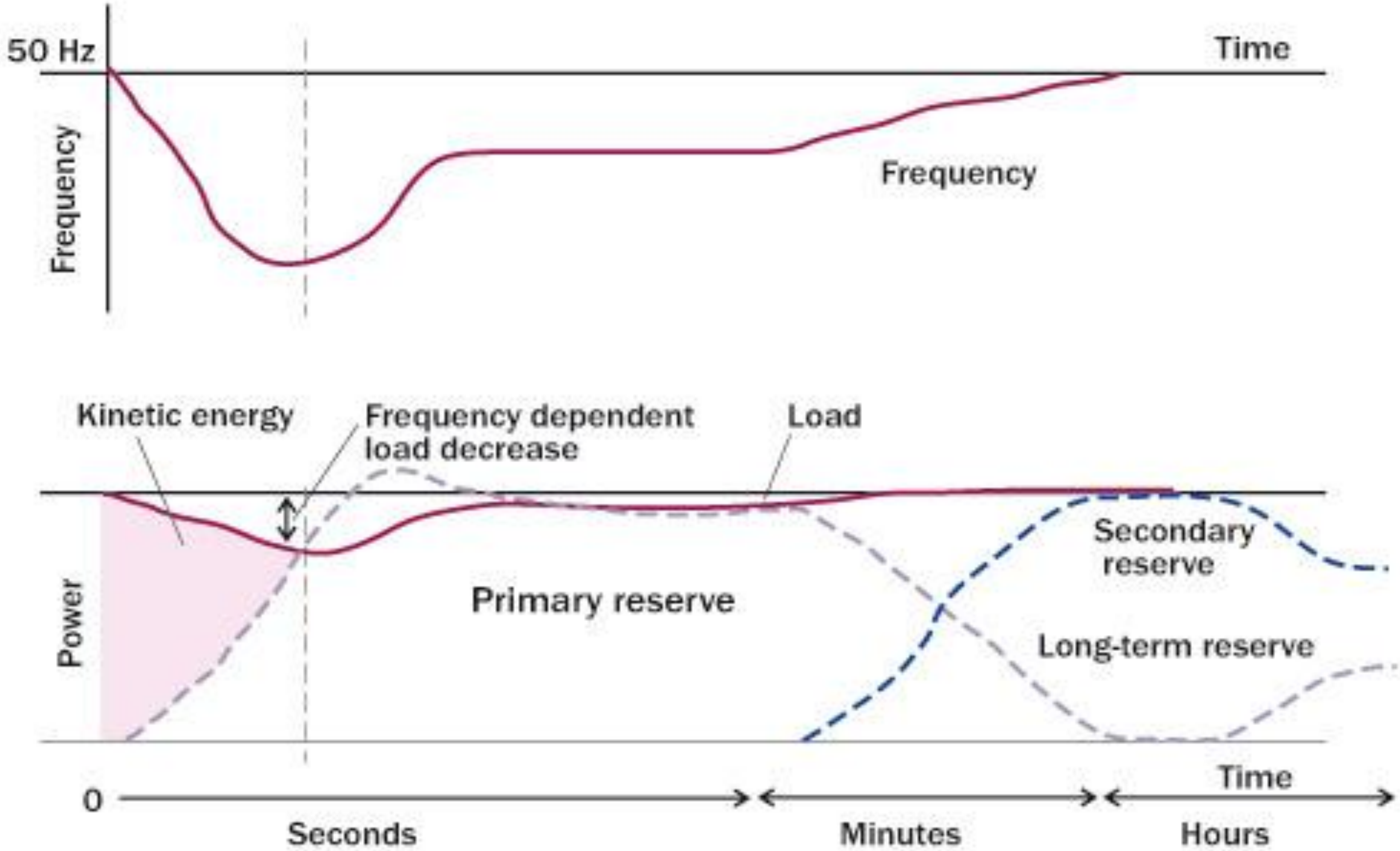
Response in seconds (0-60)

Secondary control – intends to control the average frequency level at 50.0 Hz.

Response in minutes - hours

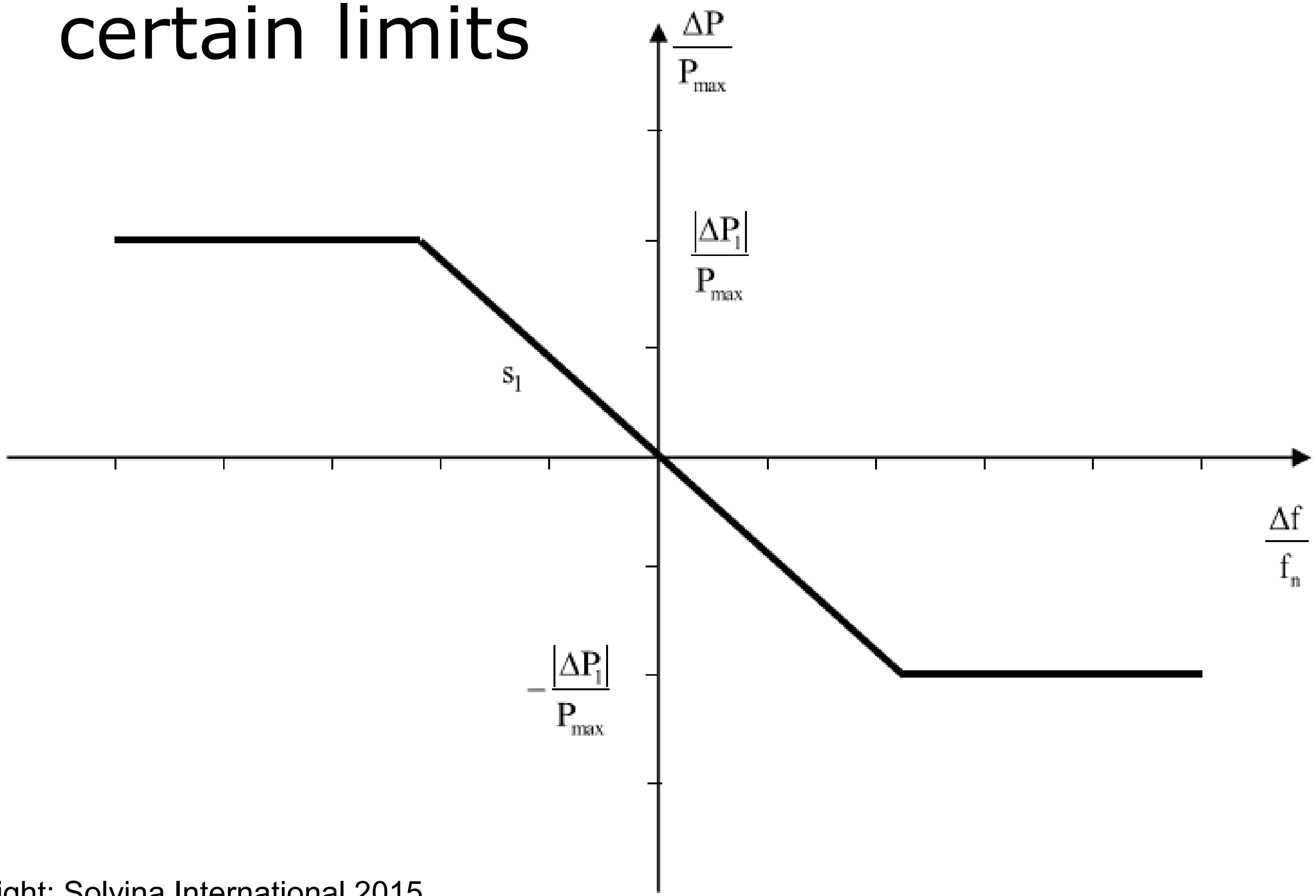
Can be automatic or manual in combination with forecasting tools and scheduling

Frequency control

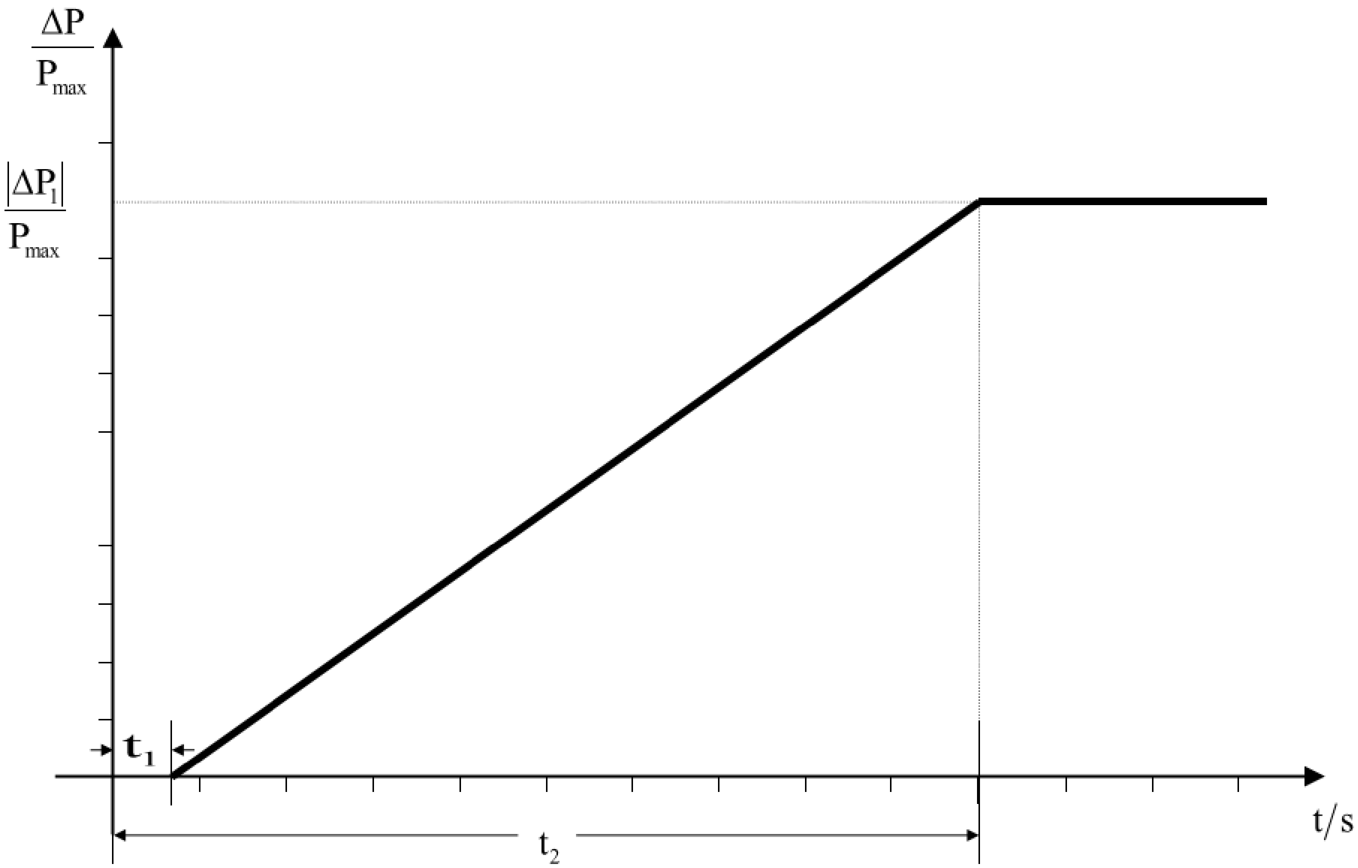


Source: Holttinen (2004a)

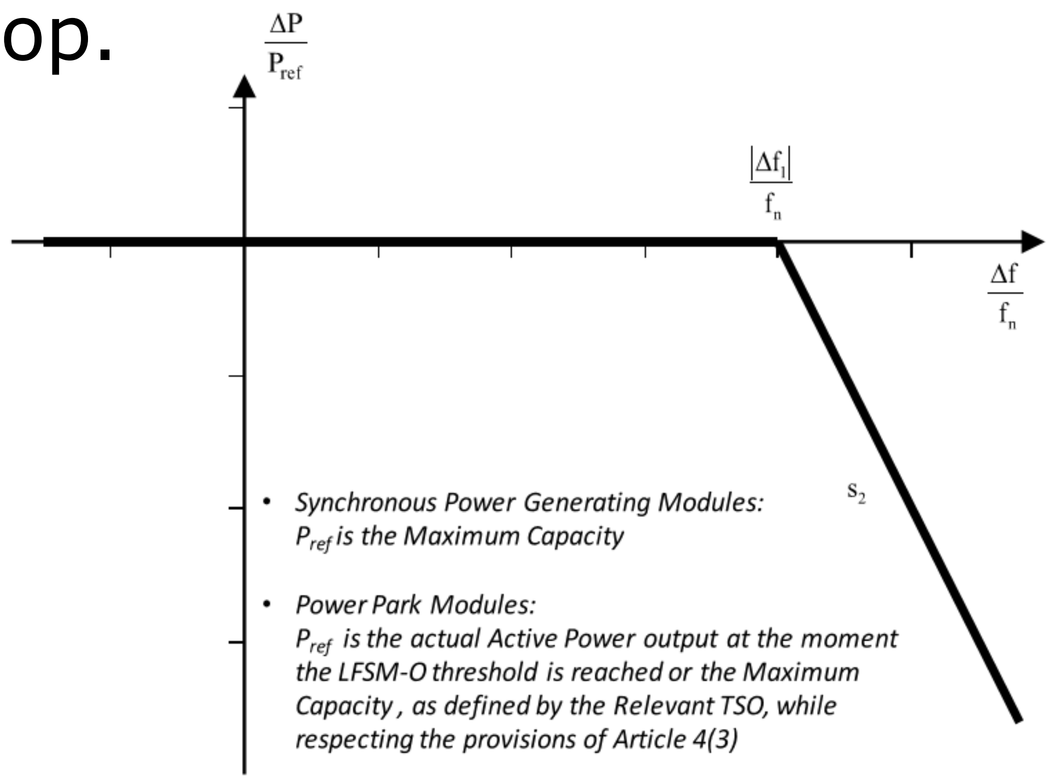
- Large units, when operating in FSM (Article 10): Response according to droop within certain limits



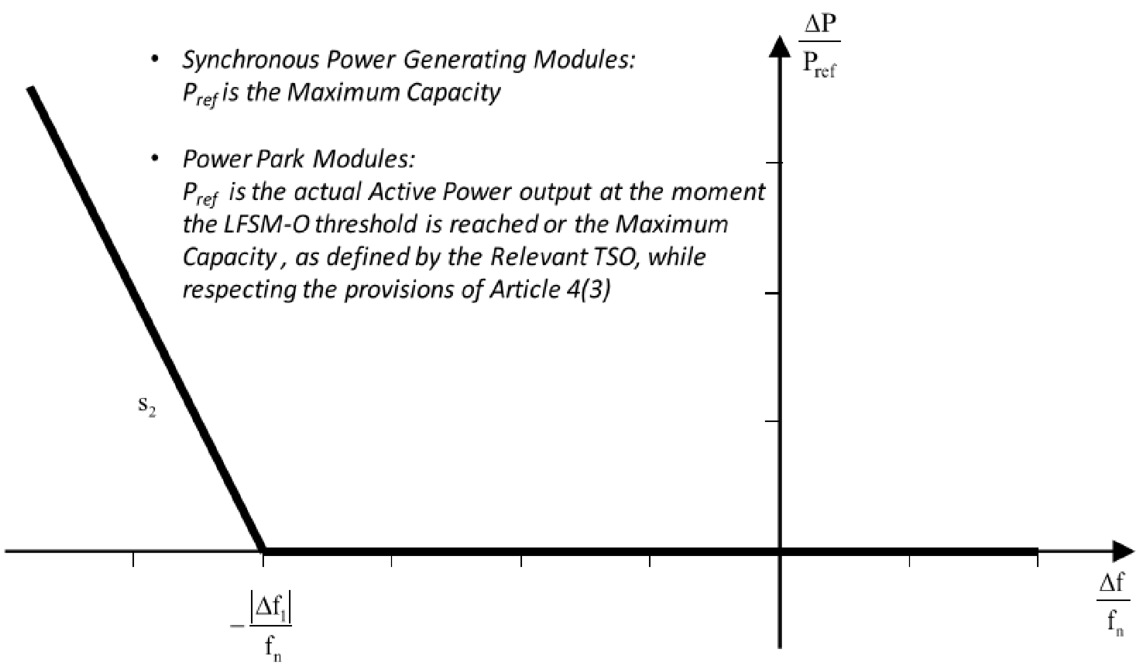
- Large units, when operating in FSM (Article 10):
  Full response within 30 s, start within 2 s.



- LFSM-O (Article 8)
  Medium and large units must respond to severe overfrequency (threshold 50.2 .. 50.5 Hz) by reducing output according to droop.



- LFSM-U (Article 10)
  Large units must, if possible, respond to severe underfrequency (threshold 49.8 .. 49.5 Hz) by increasing output according to droop.



Testing of FSM (Article 39)

a) The Power Generating Module shall demonstrate its technical capability to continuously modulate Active Power over the full operating range between Maximum Capacity and Minimum Regulating Level to contribute to Frequency Control and shall verify the steady- state parameters of regulations, such as Droop and deadband and dynamic parameters, including robustness through Frequency step change response and large, fast Frequency changes.

b) The test shall be carried out by simulating Frequency steps and ramps big enough to activate the whole Active Power Frequency response range, taking into account the Droop settings, the deadband and the Real Power headroom or deload (margin to Maximum Capacity in operational timescale). Simulated Frequency deviation signals shall be injected simultaneously into the references of both the speed governor and the load controller of the unit or plant control system if required, taking into account the speed governor and load controller scheme.

(Equipment Certificate may be used instead of part or all of the test)

- Testing

No details given on how simulating Frequency steps and ramps shall be done.

- Internal governor function?
- External equipment?

Norway

- Grid code ’FIKS’ developed in a specific technical environment:

- Almost exclusively hydropower

- Mainly Francis and Pelton turbines – fast response possible

- Weak grid and long distances – large risk for islanding

Norway

- Governor response testing
  (Appendix to FIKS)

1. **Servo loop time constant**
   Test during shutdown (dry unit) recommended.
   Test is specific for hydropower

2. **Delay – from frequency rise to start of gate movement**
   Breaker trip suggested

Norway

- Governor response testing
  (Appendix to FIKS)

3. Droop
Logging during interconnected operation.

4. Islanding
Real life tests, single or multiple units

Sweden

- Primary control support is an ancillary service, and is purchased in blocks of XXMW/Hz
- Time constant shall be <60s (Mostly Hydro)
- Testing by step response is required to show compliance (common practice)

- Island operation ability is contracted between the TSO and the plants, or regionally and utilize a combination of real tests and SSPS online method for evaluation.

Thailand

- Require plants to have an external analog frequency test input, where the National Load Dispatch Center (EGAT) can inject a test signal and evaluate the primary response regularly. *(Grid code does not clearly express this but is based on discussions with system planning department)*

Recommendations for Plants

- Phase out RGMO
- Implement PI(D) Frequency control (FGMO) with droop integrated with Load control.
- ”Power Feedback” in normal operation for predictible response
- ”Gate Feedback” in islanding for best possible stability
- Make sure process is optimally stable

Solvina International

Recommendations for Testing

- For Primary response in normal operation, **step response tests** should be carried out to get the magnitude and time constant
- For islanding, either online **"simulator testing" or real life full scale** tests should be considered. Nothing else is sufficient.
- For checking of the participation in frequency control, the generated power and frequency can be used for verification
- Any testing should be carried out by an independent party

Recommendations for Grid Control

Work out clear Crid Code for Primary Control response and for testing of the same. The requirements should be based on the unique circumstances in India.

- Grid topology
- Grid bottlenecks
- Generation mix, geograpical distribition
- ”Design base” contingencies
- Market aspects

Thanks for your attention!

Welcome to contact us for clarifications!

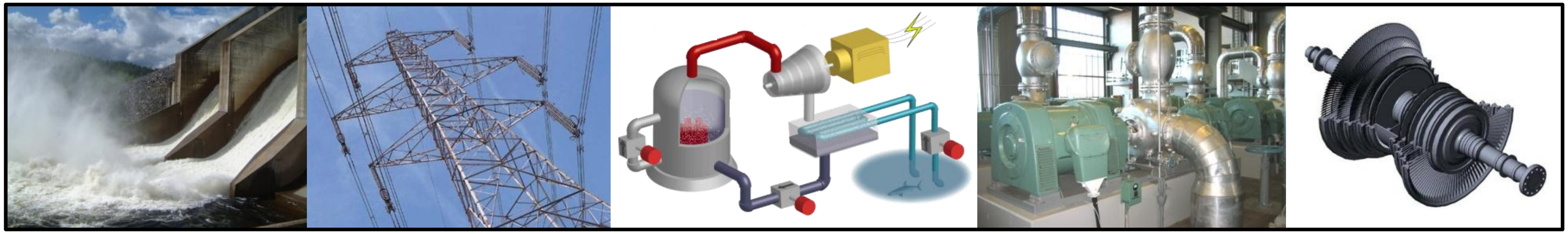
Niclas Krantz

niclas.krantz@solvina.se

+46 31 709 6304

Mr. Shahzad Alam

+91 99 10 611184



Annexure II

New Chapter on Frequency Control

Definitions

i. **Area Control Error (ACE)** is the instantaneous difference between a control area's net actual and scheduled interchange, taking into account the effects of Frequency Bias and correction of meter error. Mathematically, it is equivalent to:

   ACE = Deviation (ΔP) + (Frequency Bias) (K) * (Deviation from Scheduled Frequency) (Δf)

ii. **Automatic Generation Control (AGC)** is a mechanism that automatically adjusts the generation of a control area to maintain its Interchange Schedule Plus its share of frequency response.

iii. **Frequency Response Characteristics (FRC)** is defined as the automatic, sustained change in the power consumption by load or output of the generators that occurs immediately after a change in the control area's load-generation balance and which is in a direction to oppose a change in interconnection's frequency. Mathematically it is equivalent to

   FRC = Change in Power (ΔP) / Change in Frequency (Δf)

iv. **Frequency Response Obligation (FRO)** is defined as the minimum frequency response a control area has to provide in the event of any frequency deviation.

v. **Frequency Response Performance (FRP)** is defined as the ratio of actual frequency response with frequency response obligation.

vi. **Frequency Bias** is defined as MW/Hz associated with a control area that approximates its response to Interconnection frequency error.

vii. **Target Frequency Response (TFR)** is defined as the frequency response the synchronously integrated All India grid must provide so that the frequency deviation in case of outage of any generating station is within the defined limit.

viii. **Secondary Control** is an automatic function to regulate the generation in a control area based on secondary control reserves in order to maintain its interchange power flow at the scheduled value with all other control areas (and to correct the loss of capacity in a control area affected by a loss of production).

ix. **Primary Reserve** is defined as the maximum quantum of power which will instantaneously come into service in the event of sudden change in frequency through governor action of the generator.
x. **Reference Event** shall be defined as the largest credible contingency of generation in the grid.
xi. **Load-Damping constant** shall be defined as the percentage change in power consumption of load with one percent change in frequency.
xii. **Secondary Reserve** is defined as the maximum quantum of power which can be activated through Automatic Generation Control (AGC) to free the capacity engaged by the primary control.
xiii. **Tertiary Control** is any (automatic or) manual change in the working points of generators (mainly by re-scheduling), in order to restore an adequate secondary reserve.
xiv. **Tertiary Reserve** is defined as the quantum of power which can be activated (mainly by re-scheduling), in order to restore an adequate secondary reserve.
xv. **Target Quasi Steady State Frequency** shall be defined as the frequency at which all the primary reserves in the grid shall be activated.

Chapter XXXX Frequency Control

1. Introduction

a. It shall be the collective responsibility of all the control areas to keep the frequency within the permissible band of 49.90 to 50.05 Hz.
b. All the generators shall keep their machines under Primary Frequency Control with droop at all times. Any generating unit not complying with this requirement shall be kept in operation only after obtaining permission from RLDC.
c. The governors of all the generating units shall be free to respond to change in frequency from the nominal frequency of 50 Hz with due consideration of +/- 0.03 Hz maximum dead band.
d. Independent third party testing of primary response by all the generators shall be done at least once in three years.
e. The performance of secondary control shall be assessed in accordance with the detailed procedure to be prepared by NLDC after AGC is introduced in the country.

2. Primary Control

a. Primary reserve shall be maintained at All India level considering the reference event. The quantum of primary reserve shall be currently 4000 MW considering the credible contingency of outage of an entire 4000 MW UMPP.

b. The primary reserves shall be activated immediately when the frequency deviates from 50 Hz and goes beyond the dead band of the governors & fully come into service by 49.60 Hz, the quasi steady state frequency.

c. All the control areas shall ensure that the maximum primary reserve available with them is fully activated within 45 sec (50% within 15 sec 7 balance 50% from 14-45 sec).

d. All the control areas shall ensure that the primary reserve remains activated for at least 15 mins.

e. The Target Frequency Response of All India grid is assessed as 15000 MW/hz assuming

   i. Full activation of 4000 MW primary reserves by quasi steady state frequency of 49.60 Hz (10000 MW/Hz)

   ii. 1.5% Load-Damping constant @ average load of 120 GW (1800 MW/Hz).

   iii. Approximately 25%-30% margin on (i) and (ii)

f. The Frequency Response Obligation (FRO) of each control area shall be calculated as :

$$\text{FRO} = \frac{(\text{Control Area Demand} + \text{Control Area Generation})\ {*}\text{Target Frequency Response}}{(\text{Sum of peak demand of all control areas} + \text{Sum of peak generation of all control areas})}$$

g. The Target Frequency Response and Frequency Response Obligation shall be assessed by NLDC and approved by CERC. This shall be updated annually. A sample calculation is attached at the end of its document.

h. NLDC in consultation with RLDC shall calculate Actual Frequency Response of all the control areas in accordance with "Approved Procedure for Assessment of Frequency Response Characteristics of control area in Indian Power System".

i. The performance of each control area in providing frequency response shall be calculated

$$\text{Frequency Response Performance (FRP)} = \frac{\text{Actual Frequency Response (AFR)}}{\text{Target Frequency Response (TFR)}}$$

j. The frequency response performance (FRP) of each control area shall be graded as per following criteria:
    i. FRP >=1 Excellent
    ii. 0.75 <= FRP < 1 Average
    iii. 0.5 <= FRP < 0.75 Below Average
    iv. FRP< 0.5 Poor
k. The frequency response of each control area shall be calculated for each frequency deviation incidence in accordance with "Approved Procedure for Assessment of Frequency Response Characteristics of control area in Indian Power System" and reported to CERC on monthly basis.
l. Each power plant should have adequate facilities to log unit wise MW generation & frequency at 1 second resolution & submit the same to RLDCs / SLDCs whenever required by the latter.
m. The frequency influence in/out signal from unit control should also be telemetered to RLDC/SLDC SCADA.

3. Secondary and Tertiary Control

a. Each region shall maintain secondary reserves corresponding to the largest unit size in the region. These reserves shall be maintained in Central Generating Stations which are scheduled by RLDCs considering the merit order dispatch in accordance with the detailed procedure for operationalizing reserves to be prepared by NLDC.
b. ACE of each control area / region shall be calculated as per following formula:

    ACE = Deviation + (Frequency Bias) * (Deviation from Scheduled Frequency)
c. Frequency Bias shall be equal to FRO of each control area as a starting point.
d. The secondary reserves shall be activated within 10 seconds of ACE of a particular control area going beyond the minimum threshold limit to be identified in the detailed procedure for operationalizing reserves to be prepared by NLDC.
e. The secondary reserves shall be fully activated within 15 mins.
f. Tertiary reserves shall be maintained in a de-centralized fashion by each state control area for at least 50% of the largest generating unit available in the state control area.
g. The tertiary reserve shall be fully activated within 4 time blocks from the time ACE going beyond the minimum threshold limit.
h. The performance of secondary control shall be assessed in accordance with the detailed procedure to be prepared by NLDC after the AGC is implemented at multiple location in the country.

i. For tertiary control performance by each control area, RLDCs would work out the box plots for each control area deviation on monthly basis for the following time blocks based on SEM data:

    i. Average Frequency < 49.95 Hz
    ii. Average Frequency > 50.05 Hz

   For each state control area, the 75th percentile of box plot should be below 100 MW threshold for frequency < 49.95 Hz and 25th percentile should be above 100 MW threshold for frequency > 50.05 Hz. For generators, the MW ceiling value would be +/- 25 MW correspondingly. Illustration given at the end of this document

Illustration of Frequency Response Obligation Calculation

A	Nominal Frequency	50	Hz
B	Activation of Primary Control	+/-0.3	Hz
C	Full Activation of Primary Control	49.6	Hz
D	Average Load	120	GW
E	Self-Regulation of Load	1.5	%
F	Load response @ average load (E*D*10)	1800	MW/Hz
G	Maximum Loss of Generation	4000	MW
H	Target Generator Primary Response (G/(A-C))	10000	MW/Hz
I	Total Primary Response (load + generation) ((H+F) *1.25)	14750	MW/Hz
J	Target Primary Response (load + generation) (Total Primary Response rounded off to next 1000)	15000	MW/Hz

Region	FRO (MW/Hz)
NR	4289
WR	4837
ER	2209
SR	3445
NER	220

NR States

S no	Control Area	Max Demand	Max Generation	Frequency Response Obligation (MW/Hz)
1	Chandigarh	342		13
2	Delhi	5846	1137	273
3	Haryana	9113	3515	493
4	Himachal Pradesh	1488	1078	100
5	Jammu & Kashmir	2158	985	123
6	Punjab	10852	5795	650
7	Rajasthan	10961	7096	705
8	Uttar Pradesh	14503	7342	853
9	Uttarakhand	2034	1028	120

NR Generators

S no	Control Area	Max Demand	Max Generation	Frequency Response Obligation (MW/Hz)
1	BBMB		2668	104
2	Dadri Thermal		1808	71
3	Rihand		2960	116
4	Singrauli		1963	77
5	Unchahar		1025	40
6	Auraiya		407	16
7	Dadri CCPP		823	32
8	NAPS		422	16
9	Jhajjar		1407	55
10	DHAULIGANGA		296	12
11	Tanakpur		108	4
12	Koteshwar		413	16
13	Tehri		1092	43
14	Anta		415	16
15	RAAP B		410	16
16	RAPP C		582	23
17	AD Hydro		229	9
18	Everest		104	4
19	Karcham Wangtoo		1217	48
20	Bairasul		188	7
21	Chamera 1		585	23
22	Chamera 2		317	12
23	Chamera 3		263	10
24	Parbati-III		406	16
25	Naptha Jhakri		1633	64
26	Rampur HEP		462	18
27	Lanco Budhil		76	3
28	DULHASTI		403	16
29	Salal		681	27
30	Sewa-II		130	5
31	URI 1 HPS		525	20
32	URI 2 HPS		244	10
34	Sree Cement		345	13

WR States

S no	Control Area	Max Demand	Max Generation	Frequency Response Obligation (MW/Hz)
1	Chattisgarh	3757	4036	304
2	Gujarat	14448	11219	1002
3	Madhya Pradesh	10902	6690	687
4	Maharashtra	20594	14609	1374
5	Daman & Diu	307	0	12
6	Dadra Nagar Haveli	740	0	29
7	Goa	552	0	22
8	ESIL	702	0	27

WR Generators

S no	Control Area	Max Demand	Max Generation	Frequency Response Obligation (MW/Hz)
1	Sasan UMTPP		3845	150
2	JPL_Tamnar		1185	46
3	Mouda		969	38
4	Vindhyachal		4811	188
5	Ratnagiri Dabhol		582	23
6	TAPS (1,2,3,4)		1185	46
7	JINDAL		1045	41
8	LANCO		559	22
9	NSPCL Bhilai		493	19
10	Korba		2597	101
11	SIPAT		3576	140
12	KSK Mahanadi (Akaltara)		1175	46
13	CGPL		3862	151
14	Gandhar		649	25
15	Kawas		334	13
16	SSP		1312	51

17	KAPS		392	15
18	Dhariwal		259	10
19	EMCO		569	22
20	ACBIL+Spectrum		602	23
21	MB Power (Anuppur)		628	25
22	Balco		555	22
23	DGEN		801	31
24	VANDANA VIDYUT		0	0
25	Korba West		593	23
26	DB Power		584	23
27	Jaypee Nigrie		1196	47
28	GMR Raikheda		670	26
29	RKM Power		335	13

SR States

S no	Control Area	Max Demand	Max Generation	Frequency Response Obligation (MW/Hz)
1	Andhra Pradesh	7391	6394	538
2	Telangana	6849	2721	374
3	Karnataka	9508	7982	683
4	Kerala	3856	2199	236
5	Tamil Nadu	14171	10225	952
6	Pondicherry	352	0	14

SR Generators

S no	Control Area	Max Demand	Max Generation	Frequency Response Obligation (MW/Hz)
1	Ramagundam		2520	98
2	Simhadri		993	39
3	SEPL		604	24
4	Lanco Kondapalli		363	14
5	Kaiga		1082	42
6	NEYVELI (EXT) TPS		561	22
7	NEYVELI TPS-II		1331	52
8	NEYVELI TPS-II EXP		395	15
9	MAPS		385	15
10	Talcher STAGE II		1974	77
11	Vallur		1392	54
12	Meenakshi(MEPL)		307	12
13	Coastal Energen		1000	39
14	Kudankulam		915	36
15	Thermal Power Tech		1267	49
16	Tuticorin TPP		928	36
17	ILFS		594	23

ER States

S no	Control Area	Max Demand	Max Generation	Frequency Response Obligation (MW/Hz)
1	Bihar	3484	3121	258
2	DVC	2719	4278	273
3	Jharkhand	1153	555	67
4	Odisha	4091	5091	358
5	West Bengal	7853	5244	511
6	Sikkim	109	664	30

ER Generators

S no	Control Area	Max Demand	Max Generation	Frequency Response Obligation (MW/Hz)
1	Adhunik Power		582	23
2	GMR Kamalanga		658	26
3	Sikkim		664	26
4	Chuzachen		117	5
5	DVC		4278	167
6	MPL		1066	42
7	Sterlite		872	34
8	Teesta		543	21
9	Kahalgaon		2252	88
10	Farakka		1945	76
11	Talcher		984	38
12	Rangeet		86	3
13	Bhutan		1684	66
14	Barh		1253	49
15	JITPL		1151	45
16	Jorthang HEP		102	4

NER States

S no	Control Area	Max Demand	Max Generation	Frequency Response Obligation (MW/Hz)
1	Arunachal Pradesh	135	33	7
2	Assam	1378	466	72
3	Manipur	167	24	7
4	Meghalaya	377	269	25
5	Mizoram	101	20	5
6	Nagaland	138	53	7
7	Tripura	269	235	20

NER Generators

S no	Control Area	Max Demand	Max Generation	Frequency Response Obligation (MW/Hz)
1	AGTPP, NEEPCO		103	4
2	Doyang, NEEPCO		70	3
3	Kopili, NEEPCO		224	9
4	Khandong, NEEPCO		92	4
5	Ranganadi, NEEPCO		433	17
6	Kathalguri		267	10
7	Loktak, NHPC		108	4
8	ONGC Palatana		665	26

Note

1. The peak demand / peak generation data has been used based on the actual peak data used for assessing PoC Charges and Losses for FY 2015-16.
2. The data is non simultaneous and represents only individual peaks.
3. For load only control areas, frequency response obligation may be fixed considering 1% response from load.

Illustration of Tertiary Control Performance Assessment

High Frequency Performance Evaluation of Control Areas

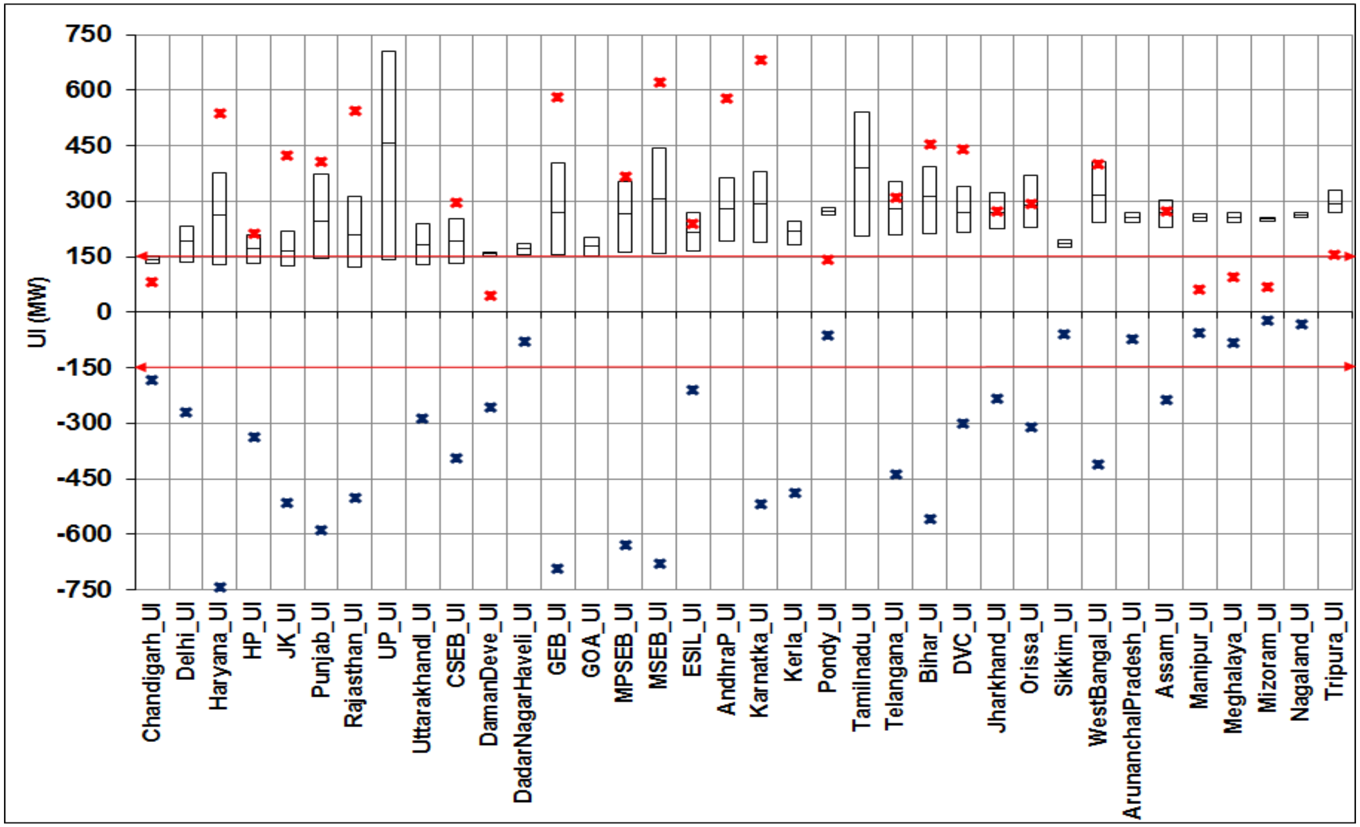


Fig.1. Deviation in MW during High Frequency (> 50.05 Hz) for the month of October 2016. No of Blocks are 405/2976

Low Frequency Performance Evaluation of Control Areas

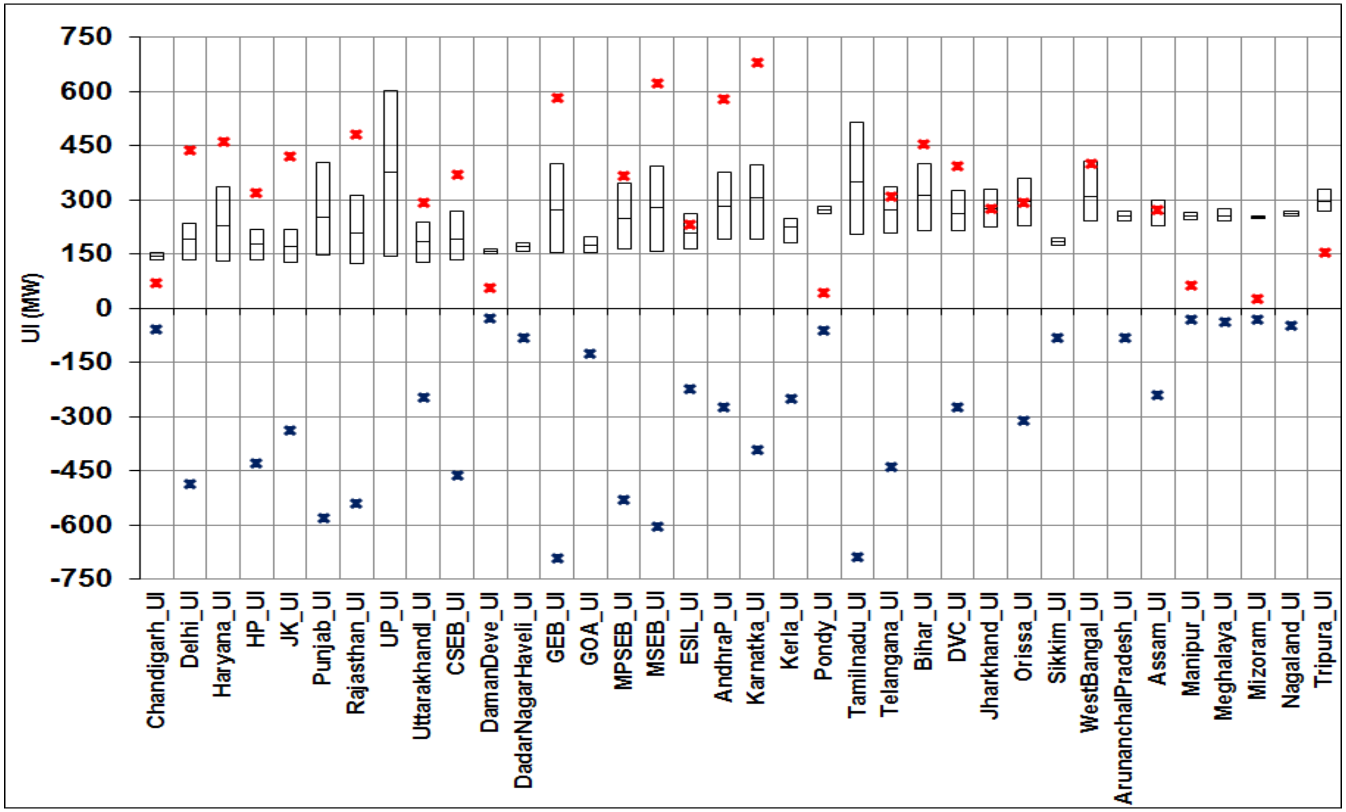


Fig 2: Deviation in MW during Low Frequency (< 49.95 Hz) for Oct 2016. No of Blocks are 134/2976