IET Renewable Power Generation

Research Article

IET Journals
The Institution of Engineering and Technology

Frequency response estimation method for high wind penetration considering wind turbine frequency support functions

ISSN 1752-1416
Received on 30th October 2014
Revised on 16th December 2014
Accepted on 3rd March 2015
doi: 10.1049/iet-rpg.2014.0364
www.ietdl.org

Ruifeng Yan, Tapan Kumar Saha ✉

School of Information Technology and Electrical Engineering, University of Queensland, Brisbane, QLD 4072, Australia
✉ *E-mail: saha@itee.uq.edu.au*

Abstract: To achieve renewable energy targets, more wind turbine generators (WTGs) are being integrated into many power networks around the world. However, unlike traditional synchronous generators, modern WTGs are driven by power electronic devices which provide almost zero inertia and frequency response to frequency related events such as generator tripping. Wind manufacturers and researchers have been working on synthetic WTG inertia support, which can better utilise the rotational nature of WTGs. However, synthetic inertia alone may be insufficient under certain circumstances to prevent automatic under frequency load shedding after generation tripping, which causes security concerns for network operation. Consequently, WTG active power control (APC, similar to governor control) should be activated to improve network security. However, APC will costly reduce WTG output from the maximum power point and result in financial concerns. Therefore when and how much APC service should be activated becomes an extremely important question, which has not been addressed in the literature. This study develops a new method to quickly estimate frequency response caused by generator tripping hence system operators can use this proposed method to continuously evaluate inertia and headroom competency and accordingly activate the amount of WTG inertia and APC required for reliable system operation.

1 Introduction

Wind penetration levels have recently increased significantly around the world. The installed wind capacity was around 24 GW in 2001, but this figure has grown to 194 GW in 2010 [1]. By the end of 2011 the possible maximum instantaneous wind penetration in some countries and regions has surged to a very high level – Ireland (108%), Iberian Peninsula (118%), Texas (41%), Western Denmark (196%) and South Australia (119%) [1, 2]. With more and more non-synchronous generation (including photovoltaic power) in the existing power networks many independent system operators (ISOs) have recognised some important issues associated with such development and frequency response is one of these issues highlighted in their reports and studies [2–4].

Popular new wind technologies – doubly fed induction generator and full converter generator – do not generally provide inertia and governor support for network frequency response [5]. Moreover, historically wind turbine generators (WTGs) have not been required to actively participate in frequency regulation [6, 7]. Therefore the existence of such non-synchronous generators displaces conventional synchronous machines and approximately 2/3 of the synchronous generators will be de-committed and 1/3 will be re-dispatched according to the Western Wind and Solar Integration Study [8]. It is reported that the Eastern Interconnection of USA and Canada has shown a downward trend of inertia response over the last 15 years [9]. With potentially more non-synchronous generators to be integrated into the power grid, the total network inertia may eventually drop to a critical level at which a generator trip event (statistically occurs several times every month for large networks [3, 10]) can make the network frequency decrease below the frequency limit consequently triggering automatic under frequency load shedding (UFLS) action and causing network stability and security concerns.

This frequency response issue has been identified by many ISOs around the world [3, 4, 11–13] and industries and researchers have already developed some synthetic inertia control strategies for frequency support [14–18]. However WTG inertia alone can cause a second frequency nadir that may be worse than the first one [11], therefore the active power control (APC, similar to governor control [17, 18]) function is required for system security. The APC works by intentionally reducing the efficiency of WTGs (as known as de-loading) through pitch control, which means wind power is generated at a level which is less than the maximum hence extra power can be produced during tripping events for frequency support. Clearly, APC for frequency response is a costly function, which will only be required during a circumstance of low inertia and governor reserve scenarios. Most likely the APC action for the frequency support purpose will only be needed collectively for a small fraction of period per year, thus the expensive APC should not be activated at all time. Therefore the important questions are: How should the necessity of APC be recognised? When and how much APC should be activated? At the same time, how much synthetic inertia should be brought on-line? All these questions have not been addressed in the current literature.

In this paper a new method for frequency response estimation is proposed, in which both frequency and voltage dependence of the load has been modelled for achieving more accurate and realistic results. This method can incorporate both traditional synchronous machines and modern WTGs with synthetic inertia and APC functions. Therefore ISOs may utilise this new method to constantly assess the competency of system inertia and available fast ramp-up reserve (also known as headroom) and then the amount of WTG synthetic inertia and APC services can consequently be activated to ensure system security. This method can provide invaluable information to ISOs on frequency response performance and it can become a very useful tool for power network operation with high wind penetration.

2 Studied power network and frequency operation criteria

The studied network contains over 2000 buses and branches and more than 300 different generators with a total installed capacity

Table 1 Frequency response standard within NERC [3]

Interconnection	UFLS threshold Δ*f*, %	Allowable B and Δ*f*, %
East	−0.83	±0.067
West	−0.83	±0.067
Texas	−1.17	±0.25
Hydro Quebec	−2.50	±0.067

of around 40 000 MW. This network has been divided into four regions – Area A (Eastern part), Area B (mid-Eastern part), Area C (mid-Western part) and Area D (Western part). Some typical seasonal scenarios with loads ranging from 15 000 MW (low demand) to 29 000 MW (high demand) are studied with full dynamic models. This large network is modelled and simulated in PSS/E [19] (PSS/E has been widely used for power system analysis around the world).

As for frequency operational criteria, different ISOs have different UFLS thresholds and allowable frequency bands. They are summarised in Table 1 [3]. In this research, conservative criteria have been chosen based on Table 1, −1.6% for UFLS threshold and ±0.2% for the allowable band of normal operation. Further, both frequency and voltage dependence of the load should be considered for more accurate results. The frequency dependence – often expressed as a load frequency relief factor – is selected to be 1% of the load for every 1% frequency deviation according to Australian Energy Market Operator [20]. As for voltage sensitivity, it normally depends on the studied network and this will be addressed in the next section.

3 Proposed method for frequency response estimation

3.1 Proposed method

To continuously evaluate the potential frequency nadir a much simpler model has to be developed rather than using a complete network model. This is because of the fact that the full model needs a huge amount of measured parameters before simulation such as machine outputs, load power values, tap changer positions, series/shunt compensation settings and transmission line status and so on. Moreover, it takes a long time to properly validate power flow of a large network against the measurement and then it also requires quite some time to run the full model for all possible scenarios to obtain a value of the potentially lowest frequency nadir point.

3.1.1 Mathematical model: A new method for frequency response estimation is proposed to solve the complication of using a full network model. This method is referenced to an average system frequency model established in [21] and this average model is modified and improved in this paper to estimate frequency nadir points. Considering all swing equations of online generators, the summation of all these equations becomes (1)

$$2 \cdot \frac{\sum_{i=1}^{n} H_i \cdot VA_i}{\sum_{i=1}^{n} VA_i} \cdot \frac{d\left(\sum_{i=1}^{n} H_i \cdot VA_i \cdot f_{i_{\text{pu}}} / \sum_{i=1}^{n} H_i \cdot VA_i\right)}{\mathrm{d}t} = \frac{\sum_{i=1}^{n} P_{\text{m}i}}{\sum_{i=1}^{n} VA_i} - \frac{\sum_{i=1}^{n} P_{\text{e}i}}{\sum_{i=1}^{n} VA_i} \tag{1}$$

Where, H_i, VA_i, f_i, $P_{\text{m}i}$ and $P_{\text{e}i}$ are inertia (s), machine base (MVA), machine frequency (pu), mechanical power (MW) and electrical power (MW) of the ith generator. For simplicity, (1) can also be expressed in a centre of inertia (COI)/centre of frequency (COF) [22] format as in (2)

$$2 \cdot \text{COI} \cdot \frac{d\text{COF}}{\mathrm{d}t} = P_{\text{m\_total}} - P_{\text{e\_total}} \tag{2}$$

3.1.2 Model modification and improvement: Further to the average frequency model, active governor models are separated in this study from the non-governor models. This is to accurately present how frequency regulation works in reality. Moreover, the electrical power calculation has been greatly changed in this paper. Previously, the electrical power only relied on load frequency model, but this calculation may not be accurate enough. Since realistic system loads cannot purely be constant power with frequency dependence and based on observations they should also have voltage dependence. According to the advice from the local ISO, the constant current model was applied to real power load and the constant impedance model to reactive power load in the studied system.

Based on the results of Fig. 1, it is found that frequency disturbance (generation tripping) may also deeply affect network voltages (Fig. 1*b*), which will consequently have a significant impact on the load (Fig. 1*a*). Therefore this voltage effect should be considered in the calculation model. However, since voltage information is not available in the model according to (1) and (2), load (or electrical power) voltage dependence has to be estimated from frequency deviation, which is partially related to voltage variation during the tripping event. It should be noted that the voltage effect may not directly be factored into the load frequency relief relationship as the voltage effect on load may occur in a very different period after disturbance compared with the impact of system frequency (Fig. 1*c*).

Based on (1) and (2), a method for frequency response estimation is proposed and illustrated in Fig. 2. The electrical power consists of a constant part, a frequency dependence part and a voltage dependence part. The constant part is the summation of all mechanical power before disturbance, hence both load and line loss are considered and the system should initially be balanced. The frequency dependence part is built based on the load frequency relief factor, and this was addressed in the previous section. The voltage dependence part has to be constructed from frequency deviation. A transfer function (estimator in Fig. 2) was

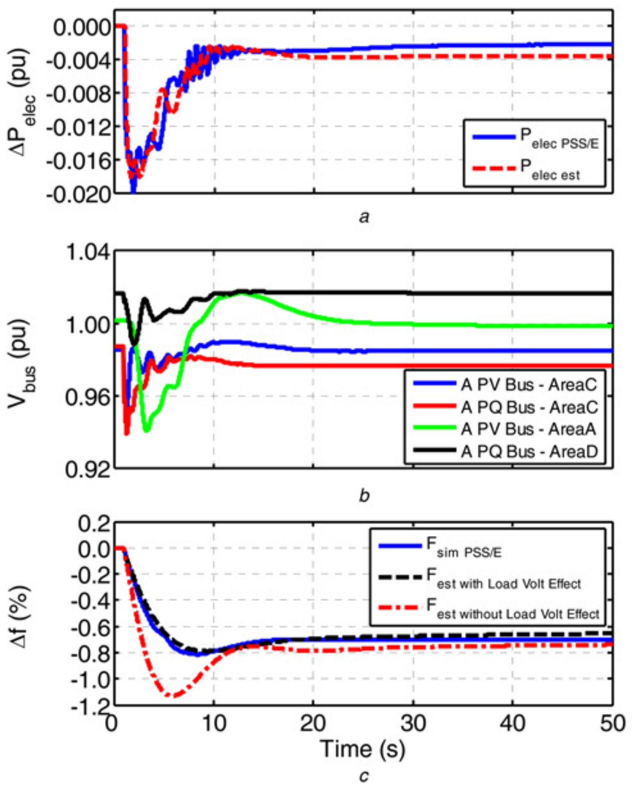


Fig. 1 *Overall voltage effect on electrical power during generation tripping*

a P_{elec}: System identification against PSS/E
b Voltage response because of generator tripping
c Frequency response comparison

IET Renew. Power Gener., 2015, Vol. 9, Iss. 7, pp. 775–782

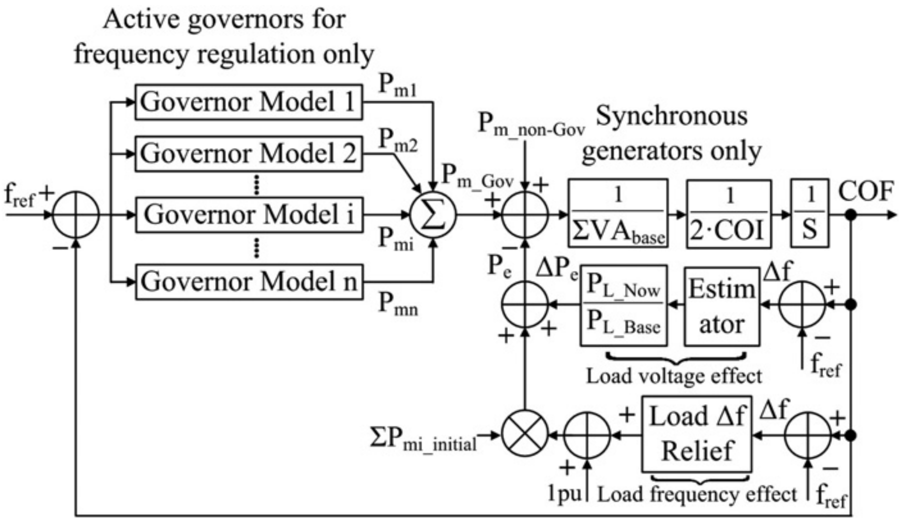


Fig. 2 *Proposed method for frequency response estimation*

estimated by system identification with the data from one instance of the full model simulation. For a certain scenario, after a generation trip in the full network, the electrical power and rotor speed of all generators needs to be recorded and the COF and total electrical power are calculated as in (1). Then the estimator shown in Fig. 2 can be determined by system identification. It should be noted that none of load frequency dependence should be modelled during the system identification process to ensure only the voltage effect can be captured. After that the resulted values from the estimator are proportionally scaled if necessary based on the loading level of the scenario. Estimation of the load-voltage dependence is essential for a valid result. Fig. 1*c* shows that if the estimation is conducted without considering this load-voltage dependence, the accuracy of result cannot be maintained. Validation of this approach will be conducted in the next section (Section 3.2), and the results show a reasonable match between the frequency response by the proposed estimation method and the frequency response by the full PSS/E simulation.

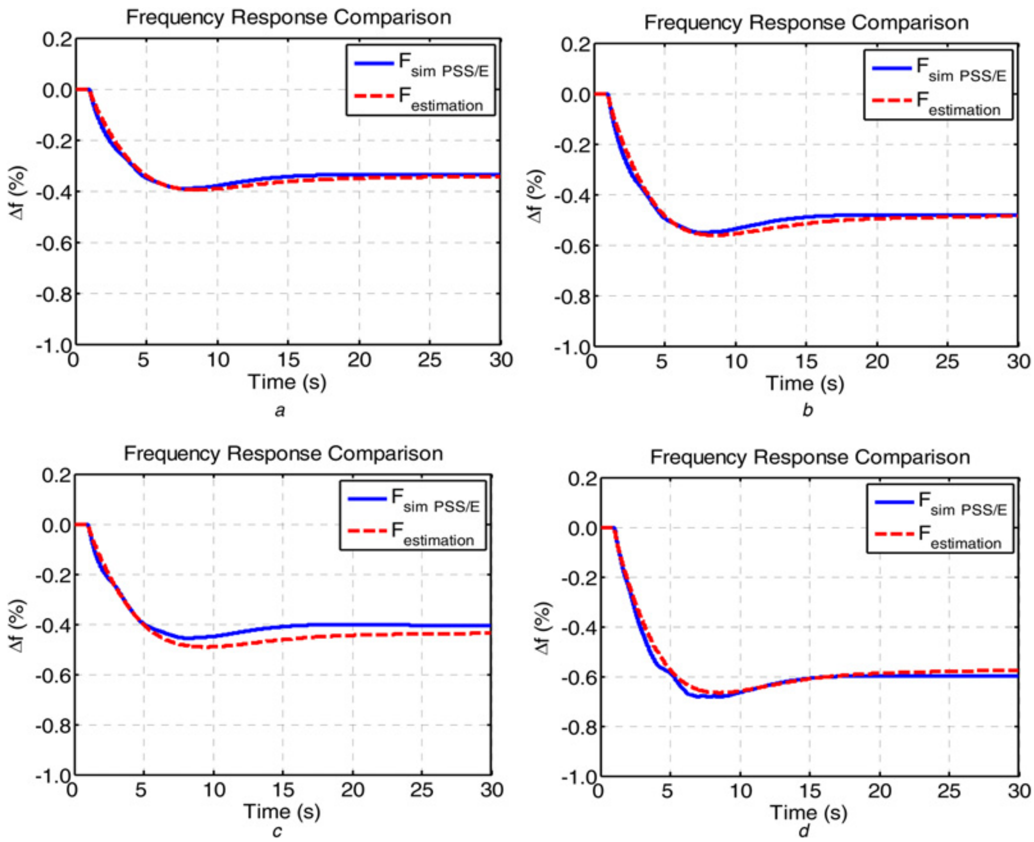


Fig. 3 *Winter high scenarios*

a 1 non-gov unit trip (654 MW) in Area B
b 2 non-gov units trip (928 MW) in Area B
c 3 gov units trip (725 MW) in Area A
d 3 non-gov units trip (1100 MW) in Area C

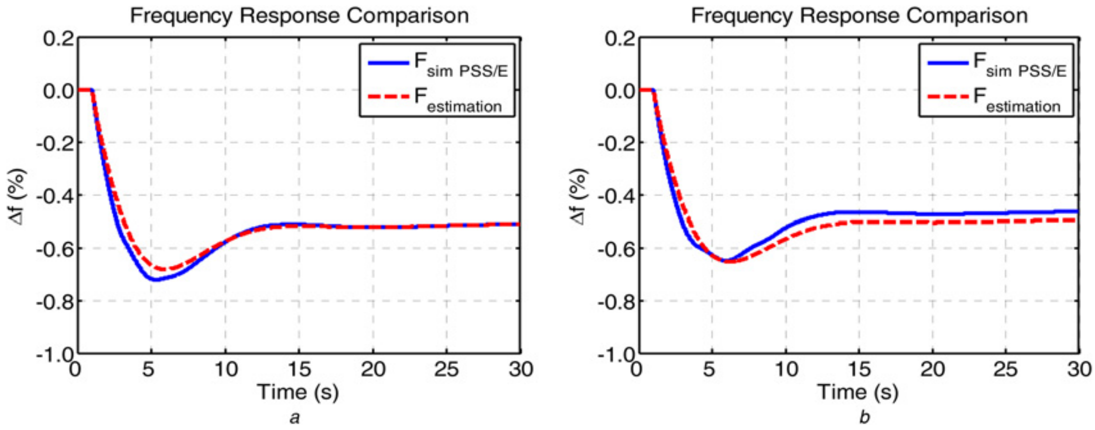


Fig. 4 *Summer low scenarios*

a 2 non-gov trip (935 MW) in Area B
b 2 gov and 2 non-gov trip (863 MW) in Area C

3.1.3 Discussion: This proposed method only needs real power outputs from all on-line generators and does not require other measurements and network load flow validation. Since normally only a fraction of all generators are participating for the service of fast frequency regulation and such service providers are relatively stable over a period of time, the estimation model in Fig. 2 is in a much simpler form than that of a full model, hence the developed method is much faster and less complicated. This model however, does not consider small signal oscillation, line power transfer capability and voltage stability limit. Therefore this method can estimate frequency response, but the estimation will not be 100% accurate. As for the final solution, full model verification in PSS/E is advised and the discretion of an experienced system operator is also extremely important for the ultimate decision.

3.2 Frequency response comparison: full model against estimation

In this section, frequency response (because of generation tripping) estimated by the proposed method is validated with that of the full model simulation results from PSS/E. Verification is conducted under different tripping combinations – machine locations, number of generators, non-governor/governor units, power outputs and loading scenarios. The results are shown in Figs. 3–5.

In summary, the frequency response curves estimated by the proposed method are reasonably close to those simulated by the full PSS/E model, in terms of frequency nadir time and magnitude. Many more frequency responses have randomly been conducted under different scenarios in this study and all of them have shown a close agreement with those of the full model simulation. For system evaluation purposes (e.g. frequency response), network operators need a tool for network performance analysis which should be as accurate as PSS/E with a faster and simpler process. The developed new method will fulfil such requirement. This is also the reason of comparing the results of the proposed method with those of the full PSS/E model.

3.3 Extension of the proposed method: WTG with inertia and APC

In this section, the proposed method will be extended to accommodate modern WTGs with frequency support functions – Inertia and APC. The well accepted GE WTG model equipped with WindInertia and APC (with the recommended parameters adopted) [18] is implemented in this study. Its control scheme is shown in Fig. 6 [18].

The challenge is to accommodate the WTG model, which does not act like a synchronous machine, into the proposed model that is based on an average synchronous machine model shown in (1) and Fig. 2. Since (1) is only for synchronous machines the existence of WTGs should not affect COI and power base in the proposed model. Therefore the idea is to add the WTG model by considering its real power contribution during frequency response. WTGs normally behave as negative loads and they only actively participate in frequency regulation during disturbances by providing extra real power. Thus only the additional power from WTGs will be counted for mechanical power contribution in the proposed model and normally WTGs should have no impact on

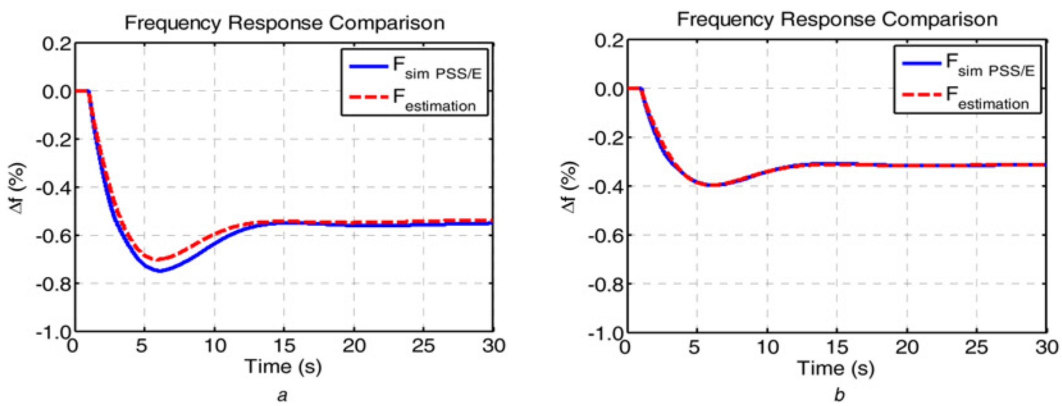


Fig. 5 *Winter low scenarios*

a 2 non-gov units trip (877 MW) in Area B
b 2 gov units trip (490 MW) in Area B

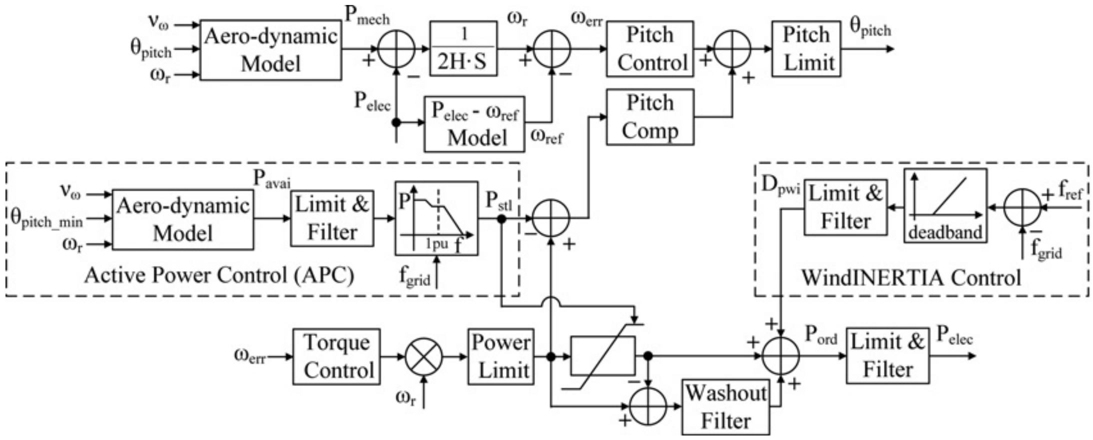


Fig. 6 *GE WTG model with inertia and APC functions [18]*

the model. The extended estimation model is illustrated in Fig. 7. This model extension will be further verified in the next section.

4 Justification of activating wind generator frequency control functions

This section will present the reasons why WindInertia alone may not be sufficient under certain circumstances; therefore costly APC has to be activated.

4.1 Wind generator – inertia support only

Owing to relatively low WTG penetration in the studied network, currently there is no concern on UFLS caused by generation tripping. This can also be observed from the frequency response conducted in Section 3 and the frequency excursion magnitudes were not even close to –1.6% (UFLS threshold). If the normal operational frequency band (±0.2%) is taken into account, the concerning frequency deviation should be around 1.4%. Realistically, a certain safety margin should be applied. However, frequency response is still not a critical issue under current conditions of the network.

Considering the rapid development of wind farms around the world, frequency response may become a serious problem in future. In this research, 7800 MW of non-synchronous generation has been integrated into the studied network to displace synchronous machines in Winter Low Load scenario (15 970 MW demand), which represents 48.8% penetration. If none of the WTG frequency control functions are activated, frequency can drop by 1.6% after a trip of generation (877 MW) as illustrated in Fig. 8. This is much more than the concerning level of 1.4% hence it is very likely to trigger UFLS. This result can successfully be estimated using the proposed method. Since the whole network inertia is lower than expected, WTG inertia support should be initiated. It should be noted that in this paper the WindInertia and APC (de-loading) functions are activated only if wind speed of a wind farm is high enough (alternatively only if the ratio of WTG generation to its rating is high enough). Otherwise, WTG is prone to stall, and its inertia cannot be utilised. In other word, the responsibility of a wind farm for frequency support should be aligned with its power generation.

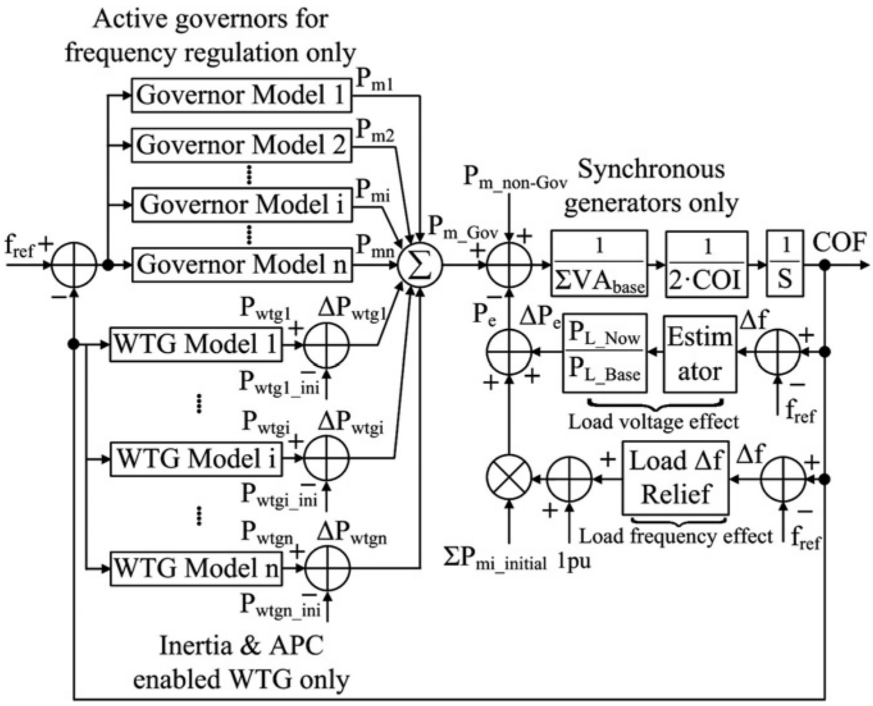


Fig. 7 *Proposed method with WTG frequency control functions*

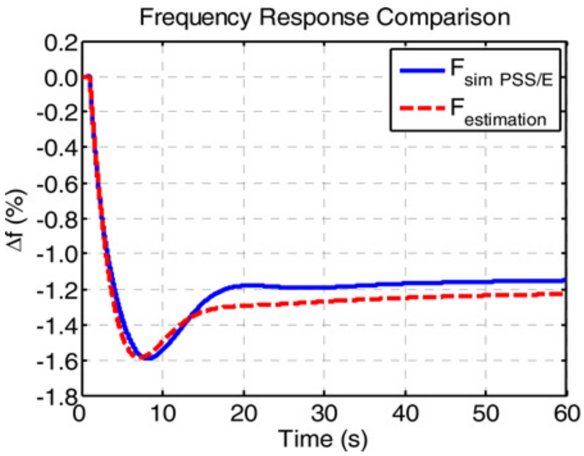
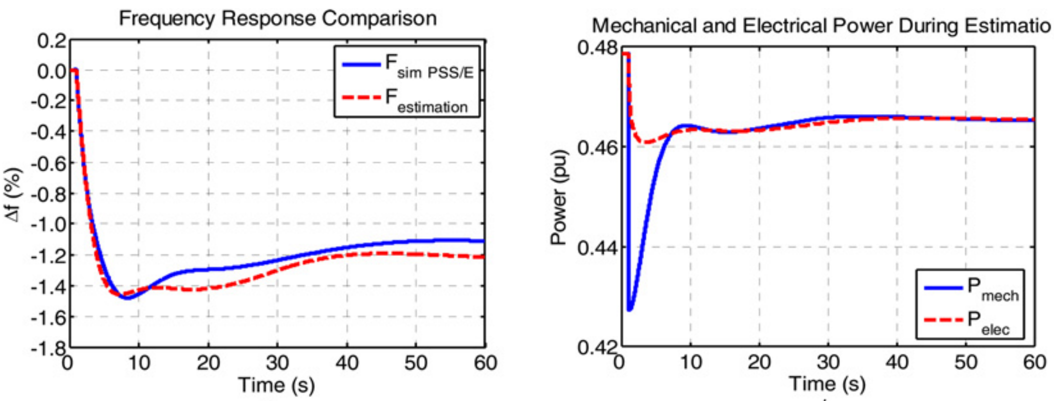


Fig. 8 *Winter low – 48.8% WTG: 877 MW trip in Area B*

If the WTGs with 917 MW power generation are called for inertia support, frequency response will certainly be improved as depicted in Fig. 9*a* where the frequency deviation is 1.48% compared with 1.6% in Fig. 8. However, this does not bring the system above the critical level – 1.4%. More inertia support is required. It can be noted that the estimated frequency response starts to show a second frequency nadir. This is mainly because of the way of simulating electrical power changes in the proposed model. It is inevitable that the estimated electrical power will have small difference to that of the full model, hence sometimes mechanical power is very close to electrical power at the first frequency nadir but just cannot catch up with electrical power (Fig. 9*b*). As a result, the estimated frequency curve has some difference from the full model simulation. However, as shown later in the section this small mismatch does not have much impact on the decisions to be made based on the estimation.

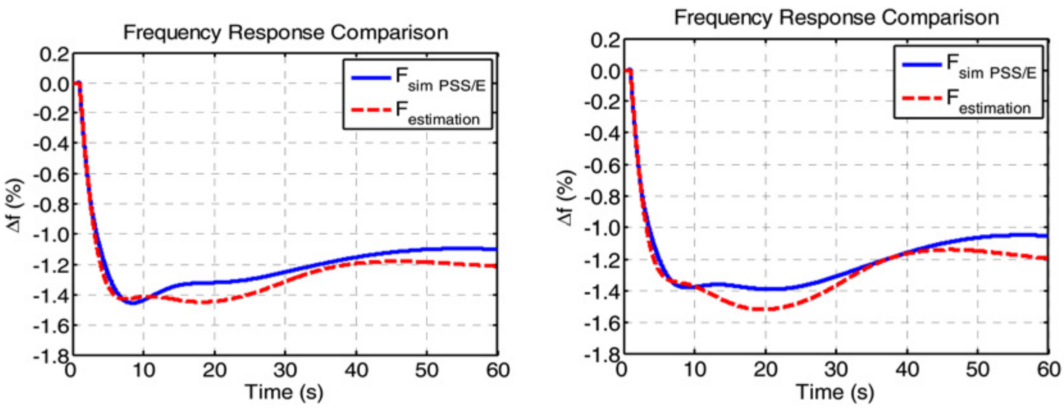
As activating WindInertia control of 917 MW WTGs is not enough to mitigate the frequency response concern, more wind farms are requested to participate in WindInertia control. However, no matter how many wind farms actively contribute to the inertia pool, the frequency deviation cannot be brought to a level, which provides a decent margin above 1.4%. Some examples of this process have been demonstrated in Fig. 10. It is worth noticing that if too much WindInertia has been committed to frequency support the first nadir point may be increased to a healthy magnitude, but the second nadir may still be very close to the critical level – 1.4% as shown in Fig. 10*b*.

The reasons for this phenomenon lie in the fundamental difference between a conventional synchronous machine and a modern WTG. To better explain this issue, a simple GE test network with two 333.3 MW synchronous generators and one 100.5 MW wind farm is simulated [18] and the results are shown in Fig. 11. During frequency response, because of the governor droop function the frequency level after disturbance will be lower than the pre-disturbance level. According to (3), a traditional synchronous



a *b*

Fig. 9 *Winter low scenario (48.8% WTG) – a fraction of WTG with Inertia control*
a 917 MW WTG with Inertia control
b P_{mech} and P_{elec} in proposed model



a *b*

Fig. 10 *Winter low scenario (48.8% WTG) – a fraction of WTG with Inertia control*
a 1138 MW WTG with Inertia control
b 1871 MW WTG with Inertia control

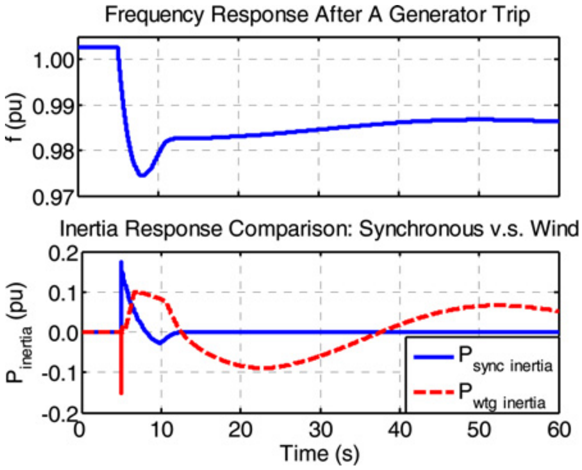


Fig. 11 *Inertia response comparison: synchronous machine against WTG*

machine will release more kinetic energy than that it will absorb, which positively contributes to frequency response. However, a WTG works on a different principle. Unlike a synchronous machine, the rotor speed of a WTG needs to be recovered after the first inertia contribution, and this will temporarily decrease WTG power output. Thus, a second nadir may appear if too much WindInertia has been activated. Overall, during the whole process a WTG will not inject extra energy into the grid as a synchronous machine. If the WTG rotor speed is not recovered, WTG may still not put additional energy into the network. Since a lower rotor speed can reduce WTG tip speed ratio and consequently power efficiency, WTG generation will drop.

$$E_{\text{release}} = \frac{1}{2} \cdot J \cdot \omega_{\text{m\_before}}^2 - \frac{1}{2} \cdot J \cdot \omega_{\text{m\_after}}^2 \quad (3)$$

4.2 *Wind generators – active power control requirement*

As shown in Section 4.1, although WindInertia control does not involve much cost, WindInertia alone may not be sufficient to bring inertia and headroom of a system into a safe level. Then the APC function should be activated to ensure the network is competent for a major tripping event. This is a much quicker responsive function than the traditional governor, hence it should be more effective for frequency control. Fig. 12 demonstrates if the APC reduces wind farm output to 90–98% of the available power, the frequency nadir will be improved and left with a certain margin to the limit of UFLS. Although APC is costly, APC service is absolutely necessary for maintaining network security in this situation. For the APC settings from 90 to 98%, 1.3–1.35% frequency deviations can be observed in Fig. 12*b*, which provides a margin of 0.1–0.05% from the UFLS limit. Whether this margin is acceptable or not in reality is up to the judgment of the involved ISO.

It can be seen from Fig. 12 that frequency response improves with more APC commitment from the wind farms, and with less APC contribution (98% APC case) frequency deviation can become larger and the second nadir can become closer to the first nadir. However, if 0.05% frequency margin is acceptable according to the local ISO, 98% APC setting will certainly be much more economical than 90–95% APC setting during operation. Therefore it is important to evaluate the optimal amount of APC contribution based on both frequency response security and APC commitment cost. However, this task is beyond the scope of the current paper, and it needs to be further investigated in the future research. It should be pointed out that Fig. 12 only shows one possible solution and it may not be an optimal solution. The reduction of wind power because of the APC control was mainly covered by the existing online synchronous generators without quick governor services, hence the total system headroom was not much affected.

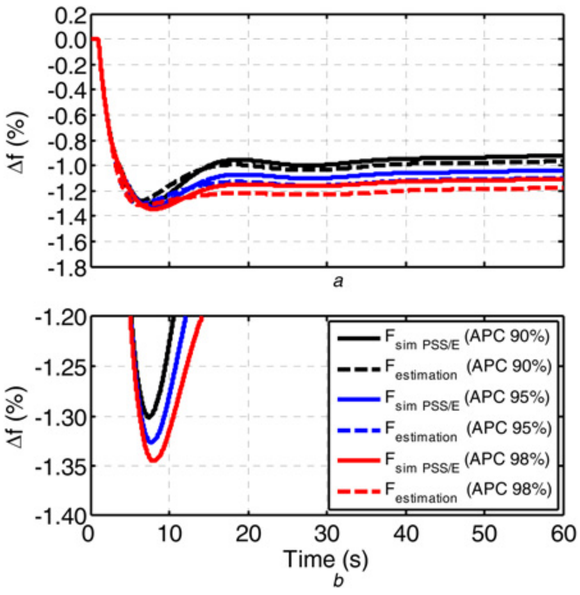


Fig. 12 *Winter low – 48.8% WTG: 1871 MW WTG – a fraction of WTG with both WindInertia and APC (90–98% for frequency = 1 pu)*

a Frequency response comparison
b Frequency nadir comparison

The estimated frequency response is very close to that of the full model simulation as illustrated in Fig. 12. This once again validates the proposed method. As for the electrical power issue mentioned in the last section, it becomes clear at this stage that this small estimation error will not have much effect on the decision making process. Since the objective is to avoid second frequency nadir and to leave a reasonable margin to the critical level (1.4%). Once the estimated frequency response starts to show the trace of the second nadir, measurement should be taken to resolve it. As the proposed method can be executed very fast, it can complete estimation for different combinations within a short time. Once a reasonable solution of APC is found, the proposed method should be able to predict the frequency response with a decent level of accuracy as shown in Fig. 12. It should be noted that the solution in this section demonstrated how the proposed model can be utilised for fast evaluation of frequency performance, and further research is needed to develop a strategy that can determine the required amount of WindInertia and APC participation in frequency response for network security using the developed method.

5 Discussion on model sensitivity of system parameters

The developed model in Fig. 7 requires many parameters, and it may be more sensitive to some parameters than the others. In general, ISOs can acquire very accurate models of both traditional generators and WTGs, and their power generation information can be obtained every couple of seconds through supervisory control and data acquisition system. Therefore fairly accurate values of many parameters are readily available, and discussions on model sensitivity will focus on the system parameters that are not measured or available and may vary during operation. On this ground, system COI, WindInertia gain and load frequency relief factor are selected to analyse model sensitivity. Fig. 13 shows their impacts on frequency response.

It can be observed that system COI does not have significant influence on frequency response (Fig. 13*a*), but the WindInertia gain that controls the wind inertia response magnitude has a reasonable impact on frequency nadir (Fig. 13*b*). In contrast, the load frequency relief factor may considerably affect frequency response (Fig. 13*c*). This implies that if the ISO uses an optimistic

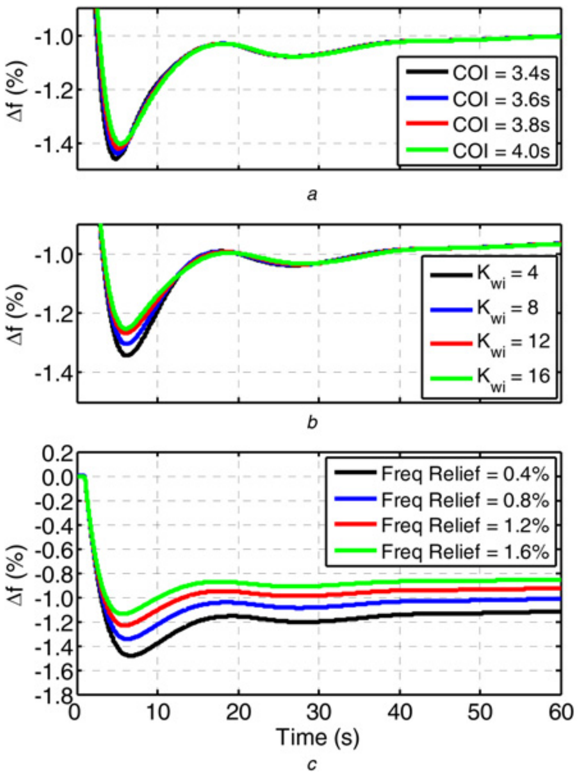


Fig. 13 *Impacts of system COI, WindInertia gain and load frequency relief factor on frequency response*

a Impact of system center of inertia
b Impact of Wind inertia gain
c Impact of load frequency relief

load frequency relief factor (a higher value, e.g. 1.6%, but in reality it is 1% instead), frequency deviation will be wrongly estimated to a relatively lower level. As a result, wind frequency support may be regarded as unnecessary; however, this may be really needed in reality.

6 Conclusions

This paper proposes a new method for estimating power system frequency response because of generation tripping. This method can include both conventional synchronous machines and modern WTGs with frequency support functions – WindInertia control and APC. Moreover, both frequency and voltage dependence of the load has been successfully incorporated into the established model. A new load-voltage dependence model has been developed, and it has shown that this model is vital for the accuracy of frequency response estimation. The simulation results have shown excellent performance of the proposed method. It requires fewer parameters from the system, runs much faster in simulation and has an acceptable level of accuracy.

Increase of non-synchronous generation has displaced many traditional synchronous machines and this trend has raised concern on inertia and headroom competency of power networks. In the future, with a high level of non-synchronous penetration a common generator tripping may push grid frequency to drop below the limit causing UFLS, which significantly affects power system security. This situation should quickly be identified and WTG inertia support should be initiated. However, under certain conditions WindInertia alone cannot provide frequency support to a satisfactory level, hence the costly APC function should be activated for system security. The proposed method can quickly provide the ISOs with invaluable information, such as whether the system is at a risk of UFLS, hence the ISOs can accordingly take actions to resolve the risk. If the developed model is incorporated into the program of the ISO network, it will be extremely helpful to quickly estimate the amount of WindInertia and APC required for maintaining frequency response to an acceptable level. Future work will focus on how to systematically determine the optimal WTG inertia and APC support using the proposed method.

7 Acknowledgment

The authors would like to thank the Australian Research Council for their financial support through a Linkage Project.

8 References

1 Ecar Energy for Australian Energy Market Operator (AEMO): 'Wind integration in electricity grids: international practice and experience', 2 October 2011, http://www.aemo.com.au/planning/0400-0049.pdf, accessed 6th October 2013
2 Energy nautics GmbH: 'Germany, Lessons Learned From International Wind Integration Studies', Commissioned by Australian Energy Market Operator (AEMO), 16 November 2011, http://www.uwig.org/AEMO-WPA4-Report-by-Energynautics-Nov2011.pdf, accessed 6th October 2013
3 North American Electric Reliability Corporation (NERC): State of Reliability Report, 2013, http://www.nerc.com/pa/RAPA/PA/Performance%20Analysis%20DL/2013_SOR_May%2015.pdf, accessed 8th October 2013
4 Australian Energy Market Operator (AEMO): '100 per cent renewables study – modelling outcomes'. Final report, July 2013, http://www.climatechange.gov.au/sites/climatechange/files/documents/08_2013/100-percent-renewables-study-modelling-outcomes-report.pdf, accessed 9th March 2014
5 Anaya-Lara, O., Jenkins, N., Ekanayake, J.: 'Wind energy generation systems: Modelling and control' (Wiley, Hoboken, NJ, USA, 2009)
6 Ecar energy for australian energy market operator (AEMO): 'Wind Integration: International Experience: Review of Grid Code', 2 October 2011, http://www.aemo.com.au/planning/0400-0050.pdf, accessed 6th October 2013
7 Tsili, M., Papathanassiou, S.: 'A review of grid code technical requirements for wind farms', IET Renew. Power Gener., 2009, 3, (3), pp. 308–332
8 National renewable energy laboratory (NREL): 'Western wind and solar integration study', prepared by GE Energy, http://www.nrel.gov/docs/fy10osti/47434.pdf, accessed 20th October 2013
9 Ingleson, J.W., Allen, E.: 'Tracking the eastern interconnection frequency governing characteristic'. IEEE Power and Energy Society General Meeting, 2010
10 Australian energy market operator (AEMO): 'Power system adequacy for the national electricity market', 2012, http://www.aemo.com.au/Electricity/Resources/Reports-and-Documents/Power-System-Adequacy. Accessed 20th November 2013
11 Ruttledge, L., Miller, N.W., O'Sullivan, J., Flynn, D.: 'Frequency response of power systems with variable speed wind turbines', *IEEE Trans. Sustain. Energy*, 2012, **3**, (4), pp. 683–691
12 Chavez, H., Baldick, R., Sharma, S.: 'Regulation adequacy analysis under high wind penetration scenarios in ERCOT Nodal', *IEEE Trans. Sustain. Energy*, 2012, **3**, (4), pp. 743–750
13 Margaris, I.D., Hansen, A.D., Sørensen, P., Hatziargyriou, N.D.: 'Dynamic security issues in autonomous power systems with increasing wind power penetration', *Electr. Power Syst. Res.*, 2011, **81**, pp. 880–887
14 Vidyanandan, K.V., Senroy, N.: 'Primary frequency regulation by deloaded wind turbines using variable droop', *IEEE Trans. Power Syst.*, 2013, **28**, (2), pp. 837–846
15 Varzaneh, S.G., Gharehpetian, G.B., Abed, M.: 'Output power smoothing of variable speed wind farms using rotor-inertia', *Electr. Power Syst. Res.*, 2014, **116**, pp. 208–217
16 Morren, J., Pierik, J., de Haan, S.W.H.: 'Inertial response of variable speed wind turbines', *Electr. Power Syst. Res.*, 2006, **76**, pp. 980–987
17 Wang-Hansen, M., Josefsson, R., Mehmedovic, H.: 'Frequency controlling wind power modeling of control strategies', *IEEE Trans. Sustain. Energy*, 2013, **4**, (4), pp. 954–959
18 Clark, K., Miller, N.W., Sanchez-Gasca, J.J.: 'Modelling of GE wind turbine-generators for grid studies', Version 4.5, GE Energy, http://www.ge-energy.com/content/multimedia/_files/downloads/EC_PSLF_Modeling%20of%20GE%20Solar%20Photovoltaic%20Plants%20for%20Grid%20Studies_GE_Solar_Modeling-v1-1.pdf, accessed 25th April 2013
19 PSS/E, Siemens: http://www.energy.siemens.com/hq/en/services/power-transmission-distribution/power-technologies-international/software-solutions/pss-e.htm, accessed 25th November 2012
20 Australian Energy Market Operator (AEMO): Integrating Renewable Energy – Wind Integration Studies Report, 2013, http://www.aemo.com.au/Electricity/Planning/Integrating-Renewable-Energy, accessed 12th December 2013
21 Chan, M.L., Dunlop, R.D., Schweppe, F.: 'Dynamic equivalents for average system frequency behaviour following major disturbances', *IEEE Trans. Power Appar. Syst.*, 1972, **PAS-91**, (4), pp. 1637–1642
22 Stanton, S.E., Waggoner, D.R.: 'A center-of-inertia transform applied to transient responses of nonlinear power systems'. The 21st Annual North-American Power Symp., 1989, pp. 205–210