Impact of Large Scale Demand Side Response on System Frequency– A Case Study

Hassan W. Qazi, Zakir H. Rather, Damian Flynn

Electricity Research Centre,
University College Dublin, Ireland
hassanwq@ucdconnect.ie

***Abstract*—Demand side response (DSR) has gained significant interest due to the time-varying and uncertain nature of renewable energy, and the challenges associated with integrating renewable technologies into power systems. DSR is considered as a fundamental component of the emerging smart grid paradigm and is seen as a potential means to achieve higher renewable targets across the globe. It is, therefore, imperative to explore the potential implications of wide-scale DSR on system operation. In particular, the impact of large-scale coordinated load switching on potential operational limits, while considering different DSR-based magnitudes and ramp rates, is considered here. The All Ireland System (AIS) projected for the year 2020, and characterised by a significant penetration of wind power has been used as a test system in the presented research study.**

***Index Terms*—Demand side management, System operation, Frequency stability**

I. INTRODUCTION

The world is in the midst of transition in the power sector, offering various opportunities while also introducing different operational issues and challenges. Renewable energy is being rapidly integrated into power systems, with wind and solar photovoltaic (PV) being the front runners. Ever since their formation, conventional power systems have possessed some inherent level of flexibility, primarily required for continuous power balancing requirements. However, due to a higher level of variable generation (VG) penetration, coupled with a displacement of conventional power plant, a requirement for, and acquisition of, sufficient flexibility has become significantly more important. Traditionally conventional power plants have remained the main flexibility source, to accommodate imbalances in generation and load, however aforementioned developments in the electricity sector have triggered an interest in demand side management. It has been shown that demand side response (DSR) can reduce the impact of wind power variability [1], resulting in a reduction in overall cost and emissions. Similar results have been claimed through load shifting and peak shaving [2]. The impact of DSR programs at higher levels of wind penetration has been tested in [3], for enabling a reduction in wind curtailment, based upon a day-ahead unit commitment model with a real-time dispatch model to account for wind forecast error. The impact of industrial, commercial and residential demand side management (DSM) is investigated in [4]. DSR has been proposed to improve the emission benefits from wind integration, where DSR is used to minimise the cycling operation of conventional power plant [5]. Integration of DSR with renewable distributed generation has been considered as a viable option for planning of distribution systems in the transition towards low-carbon sustainability [6].

While exploring the opportunities and benefits of DSR in a modern renewable energy integrated power system, it is important to consider the impacts of such programs on daily system operation. Time of use tariff (TOU) is likely to influence customer electricity usage patterns, with customers likely to consume higher volume of electrical energy during lower tariff periods (and vice versa). However the magnitude and speed of change in electricity demand patterns is unclear particularly with future prevalence of smart meters. At higher wind penetration levels, net demand can vary significantly even during peak load hours, leading to tariff induced load change of significant volume. A more sever case can be wind-driven negative electricity prices during high penetration periods in liberalized electricity markets [7], where negative electricity prices may encourage large volume of demand, leading to larger frequency nadir and higher maximum ROCOF in the system. The system operation may not be affected by smaller magnitudes of such resources; however it is much more likely to be visible in the future owing to significant DSR program deployment. Although, in practice, DSR programs will be deployed with, appropriate control strategies and due considerations to its impact on the system operation [8], worst possible case scenarios to explore the system limits need to be investigated. Such risks like large instantaneous demand switching and high ramp rate of load change, may have significant implications on the system dynamics like frequency nadir, frequency zenith, maximum rate of change of frequency (ROCOF) to name a few. The significance of such operational challenges is accentuated for isolated power systems that are likely to be more sensitive to system changes. A detailed study is therefore warranted to analyse the possible impacts such as frequency nadir, frequency zenith and maximum ROCOF, of DSR on system operation, particularly in the worst possible scenarios to identify system limits which should be considered in such programs. Findings from a research study on the All Ireland power system in connection with refinement of future DSR vision are presented in this paper which demonstrates the impact from coordinated demand switching on system frequency dynamics. The study methodology describing the power system models and the set of considered scenarios is presented in Section II. Results and discussion describing the impact of large-scale DSR are presented in Section III followed by conclusions in Section IV.

II. METHODOLOGY AND CASE STUDY DETAILS

A. System model and dispatch

The All Island System (AIS), which is a synchronised power system linking the Republic of Ireland and Northern Ireland, has been considered as the case study system. The AIS system projected for the year 2020, and developed as a single busbar dynamic model, has been employed to assess system frequency stability following large-scale, coordinated demand switching. The AIS is an islanded system with limited HVDC connection (1000 MW) to Great Britain through two interconnectors, and comprises of combined cycle gas turbines (4292 MW capacity), coal-fired plant (1323MW), open cycle gas turbines (1192 MW), pumped storage hydro plant (292 MW), combined heat and power plant (161MW), and wind farms (5 GW installed).

All generation units are assumed to be grid code compliant with an approximately 4% droop setting, and individual plant characteristics such as plant inertia are based on data provided by the manufacturers. Generator models for the individual thermal steam plant and hydroelectric plant are based on the structures defined in [9], [10]. The steam plant include a multi-stage turbine, boiler and governor; the combined cycle gas turbine model, based on [11], incorporates exhaust temperature controls and governor droop. The pumped storage plant model is a user defined model representing pumping, generating and spinning modes of operation. Fixed speed (FS) wind turbines and variable speed (VS) wind turbines are modelled separately to recognize the inertia contribution from FS wind turbines. Wind generation output is considered to be invariant during primary operating reserve (POR) provision time frame, while the potential for emulated inertia provision and governor droop control on wind generators have been neglected to clearly observe the impact of demand resource provision on the system frequency. Loads incorporate inherent frequency sensitivity based on experimental data provided in [12]. Frequency traces from various system contingencies provided by the transmission system operator have been used to validate the model over a number of years [11], [13]. A schematic layout of the single bus frequency model is shown in Fig. 1.

The Plexos production cost modelling tool was used to simulate hourly dispatch schedules for four representative days for the year 2020. Key assumptions of the Plexos 2020 model include:

- Installed wind generation of 5 GW
- System peak load of 6900 MW
- Two interconnectors – Moyle and EWIC – between AIS and Great Brittan (GB)

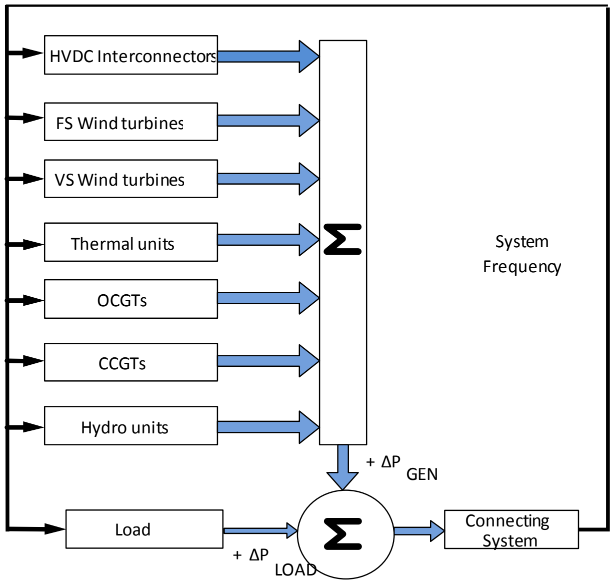

Fig. 2. The All Island System of Ireland

B. Study scope

There are two main aspects of the uncertainty associated with the user response to an external stimulus (price signal), namely the magnitude and speed of activation of the aggregate load change. In addition, a load change can be a decrease in demand in response to an external stimulus, such as an increase in the tariff, and vice versa. In order to cover a wide range of scenarios, encompassing different levels of load change magnitude and speed of response, four representative magnitudes of load change, covering load increases and decreases have been analysed, as summarised in Table I. The speed of the variation in load magnitude can also play a significant role in determining the system impact: 3 scenarios have been considered, as given in Table I. It is noteworthy that although a large (as high as 20% of expected demand) instantaneous load change is unlikely to occur in practice, it has been included here for completeness and represents the worst case scenario. The representation of different load levels and a varying generation mix has been recognised by simulating four representative days with hourly time step that cover a daily and seasonal variation of system operating conditions.

TABLE I. Demand switching characteristics

Study scenarios		
Demand switching magnitude	***Demand switching speed***	***Representative days***
5%	Instantaneous	Summer weekday
+/- 10%	20 MW/min ramp	Summer weekend
+/- 15%	50 MW/min ramp	Winter weekday
+/- 20%		Winter weekend

III. RESULTS AND DISCUSSION

The performance of the system following co-ordinated demand switching for different scenarios has been evaluated based on two criteria, namely the system frequency nadir and the initial maximum ROCOF. Renewable-driven displacement of conventional power plants reduces the system inertia and hence increases the likelihood of higher frequency deviations in such systems particularly in islanded grids. Therefore higher values of system frequency deviation may result in contracted load shedding, while high ROCOF values may trigger protection associated with distributed generation including wind farms, leading to a severe generation deficiency [13], thus provoking further frequency instability and in the worst possible case may result in cascading events leading to the system collapse.

A. *Impacts of instantaneous load change*

In the case of an instantaneous load change, the maximum ROCOF and the system frequency nadir are considered parameters of interest from a system security point of view. Power imbalance resulting in a ROCOF of more than +/- 0.5 Hz/s, measured over, a 500 ms window is considered unacceptable, while resultant system maximum frequency deviations above 0.8 Hz are deemed as unacceptable.

An instantaneous load change has been introduced in turn for 96 hours across four representative days with a magnitude varying from 5-20%. The dynamic resiliency of the system at each instance is represented by system non synchronous penetration (SNSP) as defined in (1).

$$SNSP = \frac{P_{wind} + P_{HVDC}^{import}}{P_{load} + P_{HVDC}^{export}} \quad (1)$$

where P_{wind} refers to the system wind power generation level, P_{load} is the system instantaneous demand, P_{HVDC}^{import} and P_{HVDC}^{export} are power imported/exported through HVDC interconnections.

Figure 2 shows the maximum ROCOF for each event obtained for an unpredicted load increase scenario (reflecting TOU tariff induced load increase beyond expected volume) with POR realized through droop control for each hour of the representative days. It is evident that in the considered cases, there is a correlation between the system SNSP level and the maximum ROCOF obtained. Load inertia is likely to rise in a load increase scenario, however it has negligible impacts on the ROCOF. Load increases of up to 10% are tolerable, i.e. frequency deviation and the maximum ROCOF limits are respected, for up to 60% non-synchronous penetration. However, for SNSP levels of less than 30%, even a 20% load increase can be handled without breaching the stipulated ROCOF limits.

A similar analysis has been performed for evaluating the system frequency nadir, which is generally influenced by the system inertia, volume of available fast responding frequency reserve, and, most importantly, the speed of response of reserve provision. Fig. 3 shows the system frequency nadir due to various scenarios of instantaneous load increase: up to 10% is tolerable as the frequency nadir stays above 49.2 Hz limit, however the majority of cases with 15% load increase resulted in frequency nadir below 49.2 Hz. It can be observed that the SNSP levels and frequency nadirs are weakly correlated in some scenarios, which can be explained in terms of the availability of static reserve resources and on-grid plant headroom. Static reserves such as pumped-hydro units and static reserve from HVDC interconnectors, tend to be relatively fast in response, and is likely to help arrest the sudden fall in system frequency.

In order to investigate the system limits from the perspective of over-frequency in response to load reduction through DSR, an instantaneous decrease in load was considered to replicate a scenario where customers are likely to reduce their power consumption at the commencement of a high tariff period. This analysis has been performed for two assumptions separately as described below.

A1. Generator droop control is considered as the only resource available to mitigate an over-frequency event in the system, interconnectors are not considered for any over-frequency static reserve and generator run back schemes are not deployed.

A2. In addition to generator droop control, interconnectors (if exporting at below rated capacity) provide downward static reserve and wind curtailment is realized based on the curtailment strategy provided by the TSO of Ireland, EirGrid plc.

For instantaneous load reduction in each time step of 96 hours spread across four representative days with a magnitude varying from 5-20%, Fig. 4 shows the frequency zenith for case A1 described above in section III-A. Fig. 4 also suggest that an instantaneous load reduction of up to 10% can be safely negotiated by the system, however, for a load reduction beyond 10%, the system is more susceptible to an unacceptable system over-frequency.

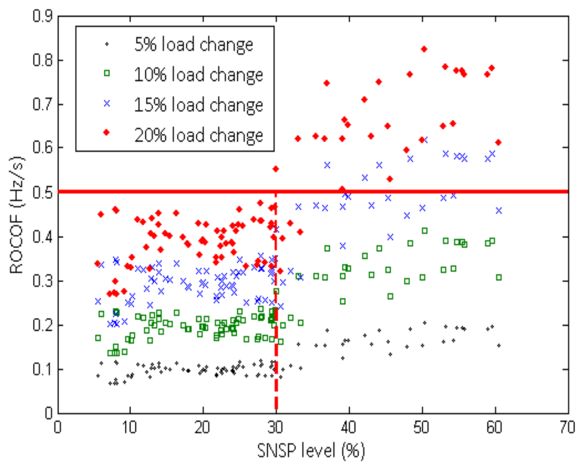

Figure 2. Maximum ROCOF results for various levels of instantaneous load increase

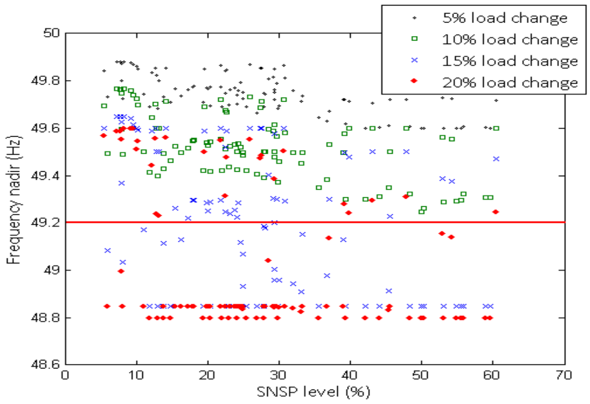

Figure 3. System frequency nadir against SNSP level for an instantaneous load increase

With an over-frequency wind curtailment scheme, the system remains well within acceptable operating conditions for all instantaneous load reductions up to 20 % as shown in Fig. 5. However, this is largely due to curtail of almost 800 MW of wind generation starting from 50.5 Hz up to 51 Hz. Wind generation curtailment, for obvious reasons, may not be a suitable methodology to control over-frequency excursions and should only be applied when other possible sources to arrest over-frequency are exhausted.

Although adoption of a wind curtailment scheme has significant effect on the improvement of the system frequency zenith following an instantaneous decrease in load, it has negligible impact on the maximum ROCOF value. This is mainly due to the fact that maximum ROCO is measured near 50 Hz while as wind curtailment is deployed at 50.5 Hz. Therefore, the results for frequency zenith suggest that over-frequency due to DSR activation is unlikely to restrict the magnitude of load decrease, however the maximum ROCOF restricts the load decrease to 10%. It is important to mention that at the very first instant of load increase/decrease, it is the magnetic energy stored in the magnetic circuit of generators that try to compensate the load imbalance, instead of the kinetic energy stored in the rotating mass which cannot change instantly due to its inertia [14]. Therefore the initial maximum ROCOF value is almost independent of the system inertia which was reflected in this research study where ROCOF values for a similar increase and a decrease in load tend to be almost identical even though the additional incoming load, increases the net system inertia and vice versa (in case of load decrese).

The key factor influencing the frequency nadir in the simulated cases is found to be the availability of fast static reserve from storage plant and HVDC interconnectors, where the availability of static reserve helps to offset the lack of system inertia in certain cases.

B. *Impacts of ramping load*

The effects of a gradual load change owing to the introduction of a price stimulus is investigated through two representative system ramps, 20 MW/min and 50 MW/min. Since the frequency zenith in the case of an instantaneous 20% load decrease (with a wind generation curtailment scheme in place) as discussed in Section III-A, was identified to be well.

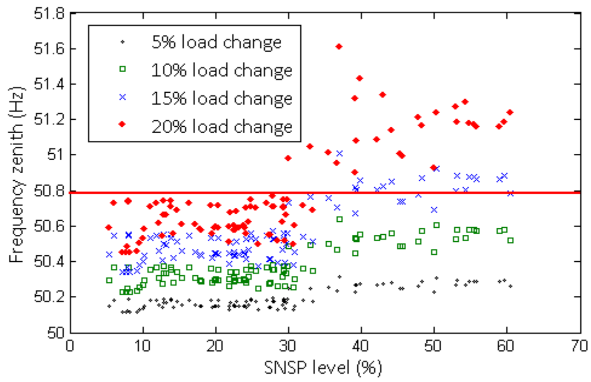

Figure 4. Frequency zenith resulting from instantaneous load decrease in the absence of wind curtailment

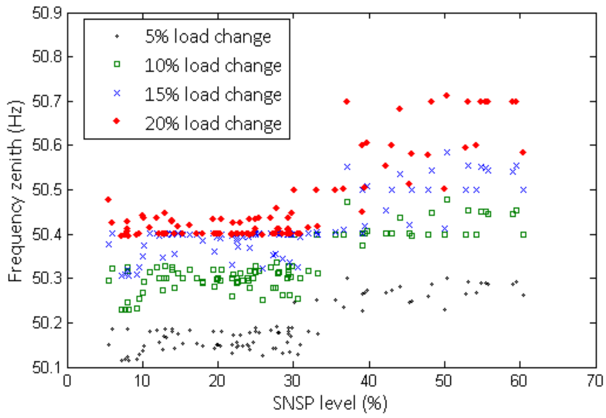

Fig. 5 Frequency zenith resulting from instantaneous load decrease with over-frequency wind curtailment

within the safe operating limits (50.8 Hz), it is highly unlikely that a ramp load increase will yield a frequency zenith beyond the safe operating limits.

Therefore, the main focus of this analysis is on different levels of load increase (5%, 10%, 15% and 20%), each with two representative ramp rates of 20 MW/min and 50 MW/min for the four representative days.

It is also worth mentioning that a non-instantaneous (ramp) increase of load of, up to 20% does not result in a breach of system ROCOF limits; therefore, the system frequency nadir limit is the only benchmark considered for evaluating the acceptability of a particular load change magnitude and ramp rate.

Since the change in load is non-instantaneous, the available system headroom is used to represent the ability to cope with a coordinated demand switching. The available headroom as defined in (2) is calculated from all available sources including online units and pumped-storage hydro units.

$$Hr\,(t) = \sum_{i=1}^{n} (Cap^{max} - D)_{i,t} \qquad (2)$$

Where $Hr(t)$ is the total system headroom for n online generators at time t, Cap^{max} is the rated capacity and D is the dispatch level of generator i.

For a 20 MW/min ramp rate, Fig. 6 shows results for different magnitudes of load increase (5%, 10%, 15% and 20%), spread over the four representative days. It can be observed that for a load increase of up to 10%, the frequency nadir remains within system operating limits for all cases. It is however, noteworthy that the net headroom that determines the aggregate ramp rate (MW/min) of the system, available in each instance plays a vital role in determining the frequency nadir.

A similar analysis is performed for a load increase with a 50 MW/min ramp rate. The results for 50 MW/min ramp rate are shown in Fig. 7. It can be observed the results for 50 MW/min ramp rate are similar to those obtained for a 20 MW/min ramp resulting in the system staying within the operating limits. In comparison to instantaneous load increase (Fig. 4), the spectra of frequency nadir for all magnitudes of load increase, is improved as the magnitude of instant load increase has decreased in ramping load for a similar net load increase as shown in Fig. 6 and Fig. 7.

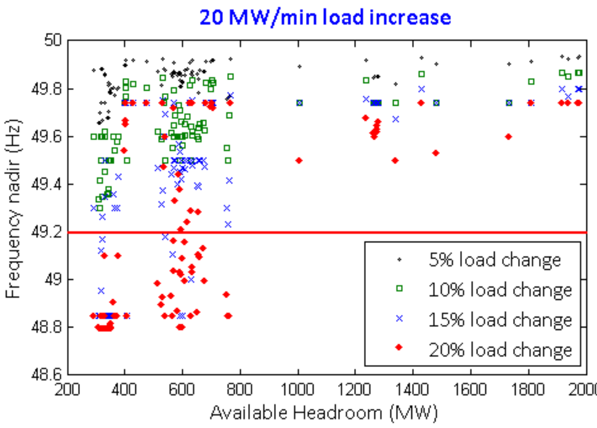

Figure 6. Frequency nadir against available headroom

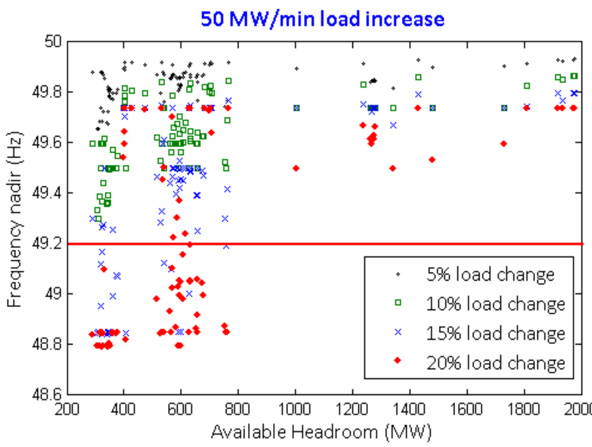

Fig. 7. Frequency nadir with available headroom for a 50 MW/min ramp rate

C. Discussion

The study shows that various operational concerns may arise in terms of frequency dynamics, while employing large-scale DSR programs, particularly at higher wind penetration levels. The study has investigated some of the worst possible cases, although with low probability to occur in practice, yet may have significant implications on the maximum frequency deviation, i.e. frequency nadir and zenith, and the maximum ROCOF of the system. TOU tarrif induced load variations of higher and undesirable volume (e,g due to switching in/out of large volume of thermostatically controlled loads) particularly at higher wind generation scenarios may impact the system frequency dynamics significantly.

Wind penetration at higher levels may lead to large variations in the net demand at any instant of a daily load curve, and any forecast error in wind generation is likely to be reflected in the net demand. Such large deviations in the net demand during peak load hours may result in low electricity price, thus encourage large scale demand response, leading to unacceptable frequency nadir or the maximum ROCOF.

Fig. 8 shows variation in the frequency nadir for various load increase levels during a summer day. Results suggest that even with ramping load variations, the frequency nadir can breach the frequency nadir limit during morning rise, peak load and even during night fall of the daily load curve. During morning rise of a load curve, generators are likely to be ramping up their generation in response to increasing demand, thus leaving limited margin for ramping up further to accommodate additional load increase, while during peak load period, generators are likely to be dispatched near or at their rated capacity, therefore leaving either no headroom in most of the units or limited margin with slow ramp rate owing to their operation near rated power.

The significance of such implications becomes more important in Islanded Systems, where the system has relatively low net inertia to start with. The extreme cases, such as the ones investigated in this study that may breach the system limits, need to be considered for secure and reliable deployment of large-scale DSR programs. Some of the possible solutions to countermeasure the impact of these worst case scenarios may include: i) For higher levels of wind penetration, emulated inertia contribution from wind turbines will help in improving the frequency nadir/zenith, therefore help in reducing the impact of DSR ii) additional infrastructure like synchronous condensers will increase the net energy stored in the magnetic field, thus improving the maximum ROCOF, in addition to inertia contribution to the system, iii) revisit and possible revision in protection settings like the maximum ROCOF values, iv) adequate tariff schemes (in evolving electricity markets) and DSR control strategies, particularly in case of switchable loads, v) adoption of adequate electricity market models in more liberalised electricity markets to avoid severe impacts of price volatility including negative prices, that is likely to trigger frequent and steep load changes, vi) increased flexibility sources and vii) recognising tariff changes within daily demand curve prediction and subsequent reserve (ramping product) policy and unit commitment procedures.

Although the worst possible scenarios investigated in this study may severely impact the system frequency dynamics, careful consideration of such scenarios in planning of large-scale DSR and associated DSM programs, should address such issues and therefore should not be a bottleneck for large-scale deployment of DSR programs.

IV. Conclusions

A research study aimed at identifying the impacts of large-scale unanticipated DSR activity on system operational limits is presented. It has been demonstrated that large-scale deployment of coordinated DSR may in extreme cases breach system limits and compromise security. The results show that both the frequency nadir and ROCOF limits may get violated in various worst-case scenarios and therefore need to be considered in the planning of DSR programs. The results suggest that the large-scale DSR deployment may demand revisiting of system control strategies and protection settings to accommodate DSR in a secure and reliable manner.

It is however, noteworthy that the results presented in this study are conservative, since any DSR activity on the system is likely to be forecasted beforehand, resulting in the deployment of mitigation measures in anticipation. The system can therefore continue to accommodate DSR provided the operational policy and coordination of DSR schemes ensures the mitigation of operational issues.

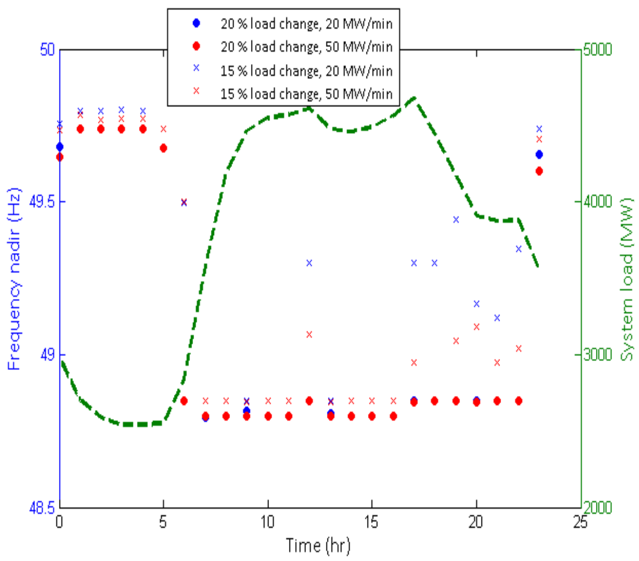

Figure 8. Frequency nadir against a daily load curve for a summer day

V. References

[1] K. Dietrich, J. Lattore, L. Olmos and A. Ramos, “Demand response in an isloated system with high wind integration,” *IEEE Transactions on Power Systems,* vol. 27, no. 1, pp. 20-29, 2012

[2] C. Gellings, “The concept of demand-side management for electric utilities,” *Proc IEEE,* vol. 73, no. 10, pp. 1468-1470, 1985.

[3] R. Sioshansi, “Evaluating the Impacts of Real-Time Pricing on the Cost and Value of Wind Generation,” *IEEE Transactions on Power Systems,* vol. 25, no. 2, pp. 741-748, 2010.

[4] P. Moura and A. De Almeida, “The role of demand-side management in the grid integration of wind power,” *Appied Energy,* vol. 87, no. 8, pp. 2581-2588, 2010.

[5] Madaeni, S.H.; Sioshansi, R. "Using Demand Response to Improve the Emission Benefits of Wind", *Power Systems, IEEE Transactions on*, On page(s): 1385 - 1394 Volume: 28, Issue: 2, May 2013

[6] Bo Zeng; Jianhua Zhang; Xu Yang; Jianhui Wang; Jun Dong; Yuying Zhang "Integrated Planning for Transition to Low-Carbon Distribution System With Renewable Energy Generation and Demand Response", *Power Systems, IEEE Transactions on*, On page(s): 1153 - 1165 Volume: 29, Issue: 3, May 2014

[7] Nordic Market Report, Development in the Nordic Electricity Market, Report-4, NordReg, Jun, 2014.

[8] Qazi, H.W.; Burke, D.J.; Flynn, D., "Challenges in utilisation of demand side response for operating reserve provision," *Innovative Smart Grid Technologies Conference Europe (ISGT-Europe), 2014 IEEE PES* , vol., no., pp.1,6, 12-15 Oct. 2014

[9] “Hydraulic turbine and turbine control models for system dynamic studies,” *Power Systems, IEEE Transactions on*, vol. 7, no. 1, pp. 167– 179, Feb 1992

[10] “Hydraulic turbine and turbine control models for system dynamic studies,” *Power Systems, IEEE Transactions on*, vol. 7, no. 1, pp. 167– 179, Feb 1992

[11] G. Lalor, J. Ritchie, M. O'Malley and D. Flynn, “The impact of combined cycle gas turbine short term dynamics on frequency control,” *IEEE Transactions on Power Systems,* vol. 20, no. 3, pp. 1456-1464, 2005.

[12] J. O’Sullivan and M. O’Malley, “Identification and validation of dynamic global load model parameters for use in power system frequency simulations,” *Power Systems, IEEE Transactions on*, vol. 11, no. 2, pp. 851–857, May 1996.

[13] O'Sullivan, J.; Rogers, A.; Flynn, D.; Smith, P.; Mullane, A.; O'Malley, M., "Studying the Maximum Instantaneous Non-Synchronous Generation in an Island System—Frequency Stability Challenges in Ireland," *Power Systems, IEEE Transactions on* , vol.29, no.6, pp.2943,2951, Nov. 2014

[14] P.M. Anderson & A.A. Faud, *Power System Control and Stability*, John Willey and Sons, 2003