Summary of Meeting and Actions

Meeting Name	Frequency Response Working Group
Meeting No.	10
Date of Meeting	Tuesday, 1st June 2010
Time	10:30am – 3:00pm
Venue	Room B2-5, National Grid House, Warwick

This note outlines the key action points from the tenth meeting of the Frequency Response Working Group.

1) Apologies for Absence

Apologies were received from Dan Jerwood (GDF SUEZ Energy UK) Bridget Morgan/ Richard Coates (Ofgem), John Welsh (Scottish Power Systems), Raul Thulin (RWE) Steve Curtis (NGET), Mark Baker (Scottish Power),Chris Proudfoot (Centrica) Damien McCool (Scottish Power Renewables), John Morris (British-energy) Claire Maxim/Guy Phillips (E.ON UK).

2) Minutes from Previous Meeting

The draft minutes of the Grid Code/BSSG Frequency Response Working Group meeting held on 28th April 2010 were approved subject to some agreed amendments and will be accessible from the National Grid Code Website.

AJ advised that the fourth paragraph under section 3 (System Inertia) does not explicitly describe the effect of decoupled plants such as wind farms which do not contribute to System Inertia. AJ advised that he would update and amend the wording. AJ to update wording of paragraph 4 item 3) of previous minutes and send to KA.

Action: AJ

3) Feedback from the May GCRP

At the May GCRP Panel meeting TI updated the panel members on the progress of the Working Group, It was conveyed to the Panel Members that the work done on Synthetic Inertia was progressing well.

The Working Group is expected to report back at the September GCRP meeting on the final Synthetic Inertia Proposals and for the November GCRP Panel meeting for the remaining frequency Response Work. The group will be expected to deliver a draft Working Group report with recommendations for Frequency Response.

It was noted that the panel were broadly happy with the progress of the Working Group. The draft Working Report expected for the November submission should cater for any market changes for the CUSC Panel meeting. Subsequently, the Panel had considered if the Working Group TOR should be expanded to include ROCOF, TI had informed the panel this would hinder the current work of the group and may delay time scales further. In addition, the Working Group did not feel they had the expertise to facilitate the work.

National Grid to update the ToR to reflect revised timescales

Action: TI

WH and AJ agreed there should be a separate working group to look at ROCOF at a later - date. It was noted that the introduction of synthetic inertia should help to prevent the problem of increasing rates of change of system frequencies following system events.

MA updated the group on the current modification proposed to facilitate the provision of mandatory frequency response from interconnectors that resulted from the IFRWG. BSC mod P259 and the CUSC amendment CAP182 were raised at the BSC and CUSC panels in May. It was also noted when the interconnector between Holland and GB - Britned will start commercial operations early in 2011. Therefore it is hoped that the changes are in place prior to full commercial operation.

TI informed the Group he will provide a presentation on the FR working groups progress at the June Ops forum.

4) System Inertia

At the last meeting, AJ provided a presentation on system inertia. Based on the "Gone Green" scenario in 2020, substantial volumes of renewable generation and HVDC schemes are envisaged in which installed capacities of such technologies will far exceed the minimum system demand. These technologies utilise power electronics which effectively decouple the mechanical prime mover from the electrical generator, thus preventing the injection of short term active power to the Transmission System. The consequence of which, being the deficit of natural short term power injection, which would normally be provided by the synchronous generators, leading to an increasing rate of change of frequency and lower minimum system frequency.

Under the SQSS, National Grid has an obligation to control system frequency to a minimum of 49.2 Hz, for an infrequent infeed loss and to recover above 49.5Hz after 60 seconds following the event. To ensure these standards are maintained under the ‘Gone Green’ scenario, it would require either the provision of very fast acting response at high cost (£15/MWhr + £50/MWhr Deload). Alternatively a requirement for plants which do not contribute to system inertia will be expected to provide a short term power injection (via a control system). This latter option is believed to be significantly cheaper and required only on plant operating in Limited Frequency Sensitive Mode.

Having completed a resume of the issue's and the effect on system inertia, AJ provided an additional presentation of the work completed to date. This included some high level requirements based on new studies completed in both Power Factory and an Energy Spreadsheet. AJ explained by modelling the wind generation it generated a short term instantaneous increase in active power of about 10% of Registered Capacity. This then decayed exponentially over a 10 second period, there by allowing the effect of zero inertia to be controlled.

AJ also advised that, any control scheme developed would need to cater for both large and small changes in system frequency. It was suggested that the control action is based on a df/dt control such that for small changes in system frequency the control system remains inactive (ie between +/- 0.003 Hz/s). For larger changes, the maximum initial power delivered is based on the rate of change of system frequency, up to a predefined limit. Thus, the aim would seek to ensure sufficient short term active power is delivered without generating over or under frequencies.

AJ advised that the high level proposal appeared to fit well within the capability of most wind turbine manufacturers (ie approximately 10% of Registered Capacity over 10 seconds). Whilst a high level proposal has been suggested, AJ advised that further study work would be required to define parameters and ensure current study results where reflective of actual system behaviour. Following completion of such work and establishment of settings, further discussions will be required with manufacturers before final legal drafting.

MC questioned what implications the requirements for an inertial response would have on the steady state and post frequency event production capability of a wind turbine, because the turbine would presumably be required to operate off the normal optimum operating point in order to deliver the inertial response. AJ confirmed that he would find out but mentioned further information was available from the references summarised at the end of the presentation.

The Group discussed commercial issues associated with the provision of a synthetic inertia. It was agreed these issues require further discussion.

It was advised that a full report together with final legal drafting would be submitted to the September GCRP. TI to speak to MA outside the meeting whether CAP182 considers Synthetic inertia.

Action: TI

At the next meeting the Group agreed to look at more studies on how plants behave, how plants should be paid for in providing frequency response.

5) Options for Future Frequency Response Market

MA presented his market example where there is a Grid Code Obligation. MA outlined three potential options with the pros and cons of each option:

a) Obligations per generating unit
b) Obligations per Portfolio
c) Obligation dependent on technology

MA made it clear to the members his pros and cons were focused on the views of the System Operator (SO) therefore the input of the members were greatly appreciated to develop these examples further.

The advantages in using option (a) Obligations on the generating unit: would result in maintaining the current arrangement; this is beneficial because of its familiarity. Furthermore it does not discriminate against non portfolio players or technology types. The frequency response volumes will be almost guaranteed, thus facilitating better system security.

In contrast, the disadvantages in implementing option (a) Obligation per generating unit: The mandatory requirement will force all new generators to have an obligation to provide frequency response; therefore inevitably stifling innovation. If frequency response is met by the current providers then new entrants will have less of an opportunity to enter the market or develop innovative response solutions. MC added that as some new generation technologies may have difficulties in meeting the full Grid Code obligations, and therefore other alternative technologies may be chosen, for example use of drum boilers over super critical coal plant. It was argued that such alternatives may not be the most effective choice overall.

MA thought that the generating unit example could consider frequency response provided by auxiliary units; he was not sure whether the Grid Code currently allows generation to employ auxiliary units to help meet FR obligations. MC pointed out that it did not; however there was a possibility for new technologies to provide such a capability. The group discussed whether plants can be integrated with old and new technologies to deliver frequency response. AJ clarified the Grid Code obligation in CC.6.3.7/CC.6.3.6 in respect of a Generating Units, Power Park Modules and DC Converters. The issue of integrating technology was discussed such as a wind turbine equipped with a FR battery system. AJ noted, a related area in the Grid Code under CC8 which does not permit a synchronised machine to make up the deficit of Reactive Power at the Generator terminals through the use of additional reactive compensation equipment such as SVC's. The group discussed whether the Grid Code should be more explicit to allow integration of different technologies or whether the wording should be ambiguous.

MA to include comments provided by the members in his example **Action: MA**

In exploring the advantages in option (b) Obligations on per portfolio unit: It became apparent it would allow providers the flexibility to determine what technologies can provide the FR service. If a technology type is not able to deliver response to an optimum level at the required time, it can be substituted for a different technology type that can. The portfolio player will have the opportunity to invest in innovation such super critical coal, as long as other plants within the portfolio are available which can compensate for the deficit; thus the provision of frequency response will always be available. Furthermore this will bring about system security and promote innovation within the portfolios. One other advantage is that if new generator technologies that may not be able to provide FR could be cheaper at providing energy than existing technologies. The hypothetical example used was that a CCGT that can provide FR may have a 70% thermal efficiency whereas a new CCGT that cannot meet the FR requirement may have a thermal efficiency of 75%.

Despite this, the negative aspects of option (b) Obligations on per portfolio unit must be considered. In shifting generation to provide frequency response at different times could result in increased costs depending on the system load at the time. This approach would favour larger portfolios over small non-portfolio providers as larger providers have a greater selection of plant. In contrast, their smaller counterpart may be restricted in what they can invest in; which could be considered to be discriminatory. The group discussed uncertainties of capability; i.e. who would be responsible if a Generator was not able to operate at the required time? The group agreed the cost factor was a major concern for this method. Several members agreed that some issues raised could not be quantified. It was stated if costs increased with this option, ultimately it would have to be passed down to the end consumer. WH suggested the option should clarify that portfolios should provide capability as well as the delivery; this should control system costs.

AJ highlighted that if a portfolio decides to divest some of its plant this would affect whether the portfolio meets their Grid Code obligation. This was supported by MC who agreed and highlighted that this could raise awareness and profile of the premium costs that frequency responsive plant could command.

In appreciating the advantages for implementing option (c) Obligations dependent on technology: it is evident different technology types will be able to connect to the system regardless of their ability. In effect, this could reduce generation procurement costs (i.e. buying off the shelf generation rather than bespoke generation for the GB market) and therefore potentially reduce power prices.

However the negative elements in implementing option (c) Obligations dependent on technology: highlight its potential to be discriminatory. At periods of low demand there is potential for a rise in costs in providing frequency response. Also, this option would not ensure adequate volumes of response availability at all times. MA stated out of the three options he had presented, this option would be the least likely to provide system security.

MA indicated as the SO he would chose option (a), Obligations per generating unit to go forward as he believed larger portfolios would have advantage over their smaller portfolios with the implementation of option (b). MC thought that option (b) offers more flexibility to small providers, a single generator could enter in the market as they currently do and provide the required response. A single plant providing 10% Primary (P),10% Secondary (S) and10% High (H) would be a portfolio player. For that reason option (a) was not so different to option (b). Alternatively Option (b) would allow the smaller plants to procure response from another source, which the Grid Code currently does not allow. Therefore it was noted that option (b) could be implemented as long as providers could / should trade capability and delivery to all the market.

MA concluded as the SO, option (a) and (b) would provide system security but there was some concerns over option (c). For transferable capability/delivery, there would need to be an incentive in place to ensure providers meet their obligations.

TI presented the group with RT’s model of the economic test for frequency response;
This model would allow a generator to carry out an economic test, in assessing whether the cost of catering for frequency response capability was economically efficient, over the cost of not providing the capability. It was suggested by a member that a third party assessment would prove beneficial than the generator itself.

By having the economic test, the risk of inefficient investment in capability would be reduced. The model indicated that the economic test would be difficult to assess, due to alternative provision costs being varied. TI gave the example of the construction of a new Europeon interconnector, which would have a significant impact on the availability or market prices for frequency response. The market trend could change; a member highlighted that trends within the year differs over seasons, markets may exist in summer but may cease to in the winter.

The costs of using the service would vary between technologies and providers; the alternative of using this method as opposed to the Grid Code obligation would not change how frequency response is priced and dispatched.

Below are the pro and cons for the model inclusive of the groups input

Pros:

- Efficient investment in capability where it is cheapest to install.
- Correct price signal can ensure sufficient capability. - CH stated that this depended on the technology types connected to the system.
- Works equally well for generators and demand side.

Cons:

- Does not guarantee utilisation prices (but may ensure sufficient competition available)
- Does not guarantee feasible mix of plant at any point in time.
- Security issues identified by AJ

It was stated for a Generator to make an economic test it would need to know how markets operate and what the likely prices are to be in the future. Currently this information is difficult to ascertain. Furthermore, some time would be needed to understand the likely power prices for the future; this itself is complex due to economic fluctuations.

A member stated that the value of the energy market outweighs the value of the frequency response market thus capital investment is reduced for the frequency response market. If the frequency response market was more profitable investors would put their time and money into investing in it. If the market could present an indicator for an opportunity it would encourage new entrants to come forward.

It was questioned whether deregulation of mandatory requirements to supply could be used to improve investment without having an obligation on the generator. Several members supported the perspective where a commercial incentive could bring about more investment.

The group discussed whether a market approach would better facilitate investment.

RT’s second Model: A traded market for Frequency Response. In considering this option providers would need to ensure capability and delivery as an alternative to the Grid Code Obligation. The market would give investment signals to the industry. Participants’ within this market would be tested and accredited before allowing them to generate thus reducing the risk of not having enough response. A possibility for an obligation on the generators or the suppliers could be enforced. Non delivery of response would lead to financial penalties such as a response imbalance price however this regime would also reward the reliable providers

The products within the market would be defined using existing definitions; Primary, Secondary and High Response and so the services can be tradable. The accurate response requirements would need to be communicated to allow for efficient despatch. Therefore daily/seasonal reporting would be required. To ensure the system requirement is met, frequency response would be considered in parallel when matching demand against generation. Providers could also be allowed to procure frequency response. Should a Generating Unit not be able to provide response due to technical failures or acquire the response, the SO will need to be able to call upon additional response, which then will be reflected in the non delivery charge.

Below are the pro and cons identified by RT inclusive of the working group input

Pros:

- Appropriate investment signals
- Appropriate cash-out ensures optimum reliability
- Frequency Response is delivered on the day to meet requirement
- Interacts with power market to give efficient despatch of energy and frequency response - The Group agreed that the power market will dominate, WH suggested in theory this may be possible however in practice this may not be the case there were too many uncertainties

Cons:

- Complex to develop
- Future requirement must be well defined to avoid inefficient levels of response being carried (although could be corrected in BM)
- The current product definitions may not be sufficient to allow a fully tradable product.
- Frequency response provision may be delivered from a concentrated part of the system although the System Operator could still instruct variations to the delivery as it currently can for energy.

TI presented his version on a Straw-man model of a traded market. This version of the traded market will also place obligations on providers for ensuring capability as well as delivery; there will be requirements for providers to build capability however the market will determine who will be dispatched.

Generators will ensure self dispatch to provide frequency response; it will be left up to them to ensure sufficient levels are available on request. Providers will be able to procure response if they are not able to provide their own. The SO will publish the frequency response requirement for the next day. This will be circulated to the respective Generators who will notify the SO through BM submissions on how they plan to match their expected response delivery. In this way, the SO will be able to monitor where and who is providing the response.

Several members indicated that the delivery of frequency response will have to be monitored regardless of which of the options are used; however, monitoring second by second delivery of response will be expensive (e.g. new metering arrangements) and complex (e.g. how do you accurately calculate non-delivery).

The question was raised as to how Frequency Resposne delievery volumes would be measured, as this was not described in the model. TI explained that the Balancing Mechanism could be used for expected delivery and in the event of non delivery the central balancer (e.g. the SO) would have to procure the deficit amount in question. The costs obtained in procuring additional response will be filtered through to the unit under delivering i.e. some form of response imbalance cost.

The group debated the cost implications for future technology to provide frequency response. A member suggested it may cost tens of millions of pounds depending on the new technology.

AJ proposed to the group that he thought with this particular option the SO would be best placed to administer which generators where selected to provide response on the day based on the data received. The response providers would bid in to a central auction to provide the response service in which a price is paid dependent on an option based approach. One concern with this option would be the lack of numbers (providers) in coming forward in the market; therefore system security issues would not be addressed. MA suggested this option was not a market based consideration as the provider does not have the ability to choose to participate or not. For that reason a provider could potentially price itself out.

Below are some key issues inherent with all the options identified.

- Who is best placed to provide response volumes - SO would be best suited to determine this
- Will this be on a per unit basis or are you able to trade that capability - the group agreed that there are some benefits in trading

- How do you ensure correct volumes are provided and who as the obligation - currently not clear on who has the obligation.

These questions would need to be applied to all the options identified

6) Going forward

After discussions on future response options, the group revisited the actions to bring clarity.

1. AJ to provide comment on the minutes - Action AJ
2. National Grid to update TOR – Action TI
3. National Grid to place System inertia presentation on the Web – Action KA
4. Discussion on CAP182 - Action TI/MA
5. The group to consider how payments for System inertia could enforced – Action all
6. AJ to carry on progressing system inertia – Action AJ

These actions were taken away and progress will be reported at the next Working Group meeting.

7) Next Meeting

The next meeting of the Working Group is on 8th July 2010 - 10:00am start to at National Grid House, Gallows Hill, Warwick.

Appendix 1 – Working Group Attendance

Members Present:

Tom Ireland	TI	Working Group Chairperson
Kabir Ali	KA	Technical Secretary
Antony Johnson	AJ	National Grid
Malcolm Arthur	MA	National Grid
William Hung	WH	National Grid
Chris Hastings	CH	Scottish-Southern
Bob Nicholls	BN	E.ON UK
Mike Chowns	MC	RWE
Francois Luciani	FL	British Energy

Apologies:

Dan Jerwood	DJ	GDF SUEZ Energy UK
Bridget Morgan	BM	Ofgem
Richard Coates	RC	Ofgem
John Welsh	JW	Scottish Power (DNO Representative)
Raoul Thulin	RT	RWE
Stephen Curtis	SC	National Grid
Mark Baker	MB	Scottish Power
Chris Proudfoot	CP	Centrica
Damian McCool	DM	Scottish Power Renewables
John Morris	JM	British-energy
Claire Maxim	CM	E.ON UK
Guy Phillips	GP	E.ON UK