STEPWISE POWER FLOW - A NEW TOOL TO ANALYSE CAPACITY SHORTAGE AND RESERVE REQUIREMENTS

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Abstract-- Frequency and active power control actions work over a time range from seconds to well over 15 minutes. Few standard computer tools are currently able to analyse slow power system dynamics in the minutes to hours range. This paper describes a new tool called *Stepwise Power Flow* (SPF), where a regular power flow algorithm is modified to run typically in 5 minute time steps. The tool includes primary (droop) response, secondary control and outages as well as frequency dependent load shedding. The algorithm is developed in an aggregated 18 bus model of the Nordic power system, and is further developed to include multiple synchronous areas, HVDC connections and wind farm dynamics. Testing and verification on a full scale Nordic model with 1257 generators is also shown. The SPF methodology enables the System Operator to assess both provision and activation of spinning reserve in the planning phases.

Index Terms-- Frequency control, Active power control, Frequency bias, Secondary reserve, Contingency, Load shedding

1 INTRODUCTION

Planning of fast and slow reserves is not only a challenge for contingency analyses like outages or other critical events. Also during normal operation, the need for medium- to long-term analyses of slow dynamics is present. Typically, frequency and active power control actions work over a time range from seconds (inertia, primary frequency control) to over 15 minutes (AGC, secondary control). Adding functions like load following, unit scheduling and tertiary control the time span is even longer.

There are currently few standard computer tools available to the System Operator to analyse slow power system dynamics in the minutes to hours range. Dynamic simulation tools are generally designed to handle fast dynamics in the seconds range and below. If such tools are used for a period of analysis exceeding a few minutes the amount of output data becomes enormous, and the simulation might become unstable. The alternative is often to use steady-state power flow tools to study the situation before and after an event.

To enable the use of steady-state power flow calculations to analyze slow system dynamics, a new tool has been developed under the name *Stepwise Power Flow* (SPF), where a regular AC power flow algorithm has been modified to run typically in 5 minute time steps.

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2 STEPWISE POWER FLOW (SPF)

The methodology of Stepwise Power Flow is developed using the MatPower package [1]. The main idea is to use a sequence of stationary power flow analyses to capture slow system dynamics in the minutes range; from stationary droop response through secondary reserves to scheduled generation changes, neglecting transient dynamics. For each time step, loads are updated and generation is distributed among all units according to schedule, unit droop and secondary control/AGC. The Swing Bus is not used to balance the system load. Outages of lines, generators and/or loads can be added as contingencies, and load shedding and generator tripping are available for serious events. In the current version, a full AC power flow is used but DC or Continuation Power Flow can also be implemented.

2.1 Outline of algorithm

Regular powerflow calculations assume balance between scheduled generation and actual load, but this is formally correct only one or a few times during the hour in a real power system where the load is always changing. A sequence of modified powerflow analyses are run in a finite number of steps between two (or more) initial powerflow cases. In the present version the system load is assumed to change linearly through the hour, while scheduled generation is changed only at the change of hour. See Figure 1.

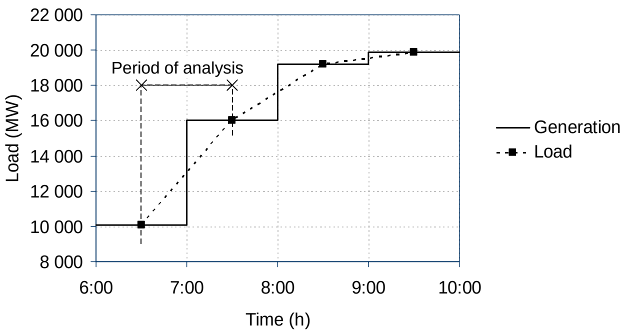

Figure 1 Period of analysis for frequency and power control

For each time step in SPF, the imbalance between generation and load is shared between all synchronized units according to their droop settings. This results in a quasi-stationary simulation of:

- active power generation and consumption
- spinning reserves and system bias

- critical line flows
- system frequency

The inputs to the algorithm are:

- power flow and topology data for two or more succeeding hours (e.g. from PSS/E)
- scheduled generation
- primary control/unit droop
- volume and price of available secondary reserves (*BalPow*)
- outages (generation, load or lines)
- available generator tripping and load shedding (*GenTrip*, *LdShed*)

The SPF flowchart is shown in Figure 2 for a simulation with increasing load. The different functions and symbols are described in the following sections.

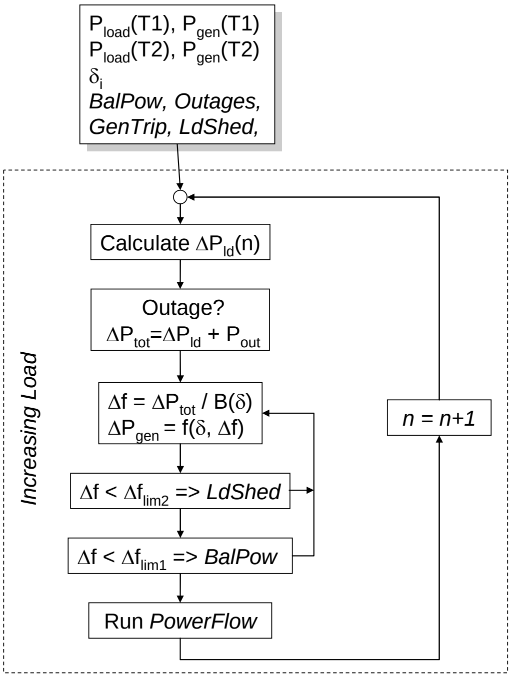

Figure 2 Flow diagram for Stepwise Power Flow (SPF) [2]

2.2 Basic droop response loop

During initialization, powerflow data for start *(n = 0)* and end *(n = N)* cases are read. In the current version the demand is assumed to increase linearly for each node *i* through the whole period:

$$\Delta P_{di} = \frac{P_{di}(n=N) - P_{di}(n=0)}{N} \ \forall i \ \text{(MW)} \qquad (1)$$

After an initial powerflow calculation, the model is running in a loop of *N* steps with incremental demand. The demand P_{di} in node *i* at step *n+1* is thus given as:

$$P_{di}(n+1) = P_{di}(n) + \Delta P_{di} \ \forall i \ \text{(MW)} \qquad (2)$$

The same calculation is made also for reactive demand. The change in demand causes a power imbalance at each time step resulting in a frequency deviation given by:

$$\Delta f(n) = -\frac{\Delta P_{tot}(n)}{B(n)} \ \text{(Hz)} \qquad (3)$$

where
$$\Delta P_{tot}(n) = \sum_{i=1}^{N_{load}} \Delta P_{di}(n) \ \text{(MW)} \qquad (4)$$

$$B(n) = \sum_{j=1}^{N_{gen}} \frac{2 \cdot P_{Rj} \cdot S_j}{\delta_j} \ \text{(MW/Hz)} \qquad (5)$$

and
N_{gen} - no. of generators
N_{load} - no. of loads
P_{Rj} - rated output of generator *j*
S_j - connection status of generator *j* [0, 1]
δ_j - droop of generator *j*

The Swing Bus compensates the change in network losses, since these are omitted from (4). The frequency deviation in (3) is used to calculate the new output of each generator *j* according to its droop settings:

$$P_{gj}(n) = P_{gj}(n-1) - 2 \cdot \Delta f(n) \cdot \frac{P_{Rj}}{\delta_j} \ \text{(MW)} \qquad (6)$$

Equations (3) - (5) assume a linear system bias. Normally, this would be a sufficient assumption, but if the new output of one or more generators exceeds the rated output, the calculation is modified to take the missing capacity and reduced system bias into account:

$$\left.\begin{aligned} \Delta P'_{gj} &= P_{gj}(n) - P_{Rj} \\ P'_{gj}(n) &= P_{Rj} \\ S'_j &= 0 \end{aligned}\right\} \quad \forall \ j \ \textit{where} \ P_{gj}(n) \geq P_{Rj} \qquad (7)$$

The total capacity deficit $\Delta P_{def}(n)$ and the reduced system bias $B'(n)$ is calculated, resulting in increased frequency deviation:

$$\Delta P_{def}(n) = \sum_{j=1}^{N_{gen}} \Delta P'_{gj} \ \text{(MW)} \qquad (8a)$$

$$B'(n) = \sum_{j=1}^{N_{gen}} \frac{2 \cdot P_{Rj} \cdot S'_j}{\delta_j} \ \text{(MW/Hz)} \qquad (8b)$$

$$=> \quad \Delta f'(n) = -\frac{\Delta P_{def}(n)}{B'(n)} \ \text{(Hz)} \qquad (8c)$$

$$=> \quad \Delta f(n) = \Delta f(n) + \Delta f'(n) \ \text{(Hz)} \qquad (8d)$$

The algorithm is looping though Equations (6)-(8) until $\Delta P_{def}(n) = 0$, creating a non-linear response in system frequency. After the total frequency deviation and corresponding generator outputs due to the load change are calculated, a regular powerflow is run to find the line flows, voltages etc. No adjustments are currently made for reactive power.

If no other control actions are active in the system, the frequency response will look like Figure 3 when used on a peak load hour in an 18 bus model of the Nordic power system [3]. The simulation is made in 5 minutes time steps between two sequential powerflow cases. Scheduled generation is assumed to come online after 25 minutes. The resulting "saw-tooth" frequency response is very similar to the measured response from 05:30 to 06:30 shown in Figure 4.

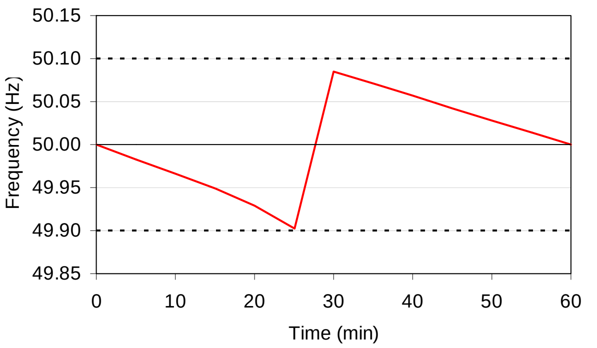

Figure 3 Simulated frequency due to load increase

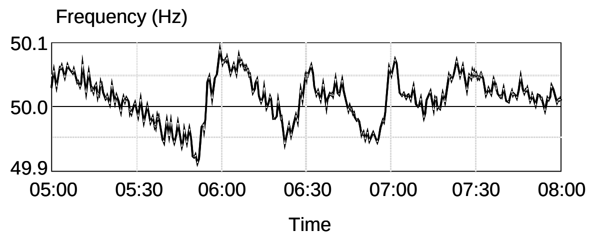

Figure 4 Measured frequency during morning load increase in Nordic system [4]

In the simulation shown in Figure 3 the available spinning reserve capacity is deliberately reduced to create a stressed system. Shortly before the change of hour the slope of the droop response increases due to generators reaching rated capacity. These units will no longer contribute with spinning reserve, causing a sharp drop in system bias (Eq. (8.8b)) as shown in Figure 5. The frequency trend in this period doesn't look very dramatic, but shortly before new generation is brought online, the system bias is reduced to less than 6,000 MW/Hz, while the System Operator has in his hourly schedule an estimated bias of 11,500 MW/Hz. If an outage should occur in this period the consequences could be dramatic.

A similar but inverted droop response would result if the simulated period had a load *decrease* instead of increase. Such simulations are not shown here.

The algorithm also generates a list of the highest loaded branches (lines or transformers) for each time step. However, since the 18 bus model uses aggregated generators and a simplified network representation, voltage levels and transmission losses are not critical for the simulations shown.

Note also that the algorithm described above is decoupled in time. Each time step is calculated incremental to the previous without further knowledge about the history of the system. This makes the algorithm much simpler and easier to adjust or expand.

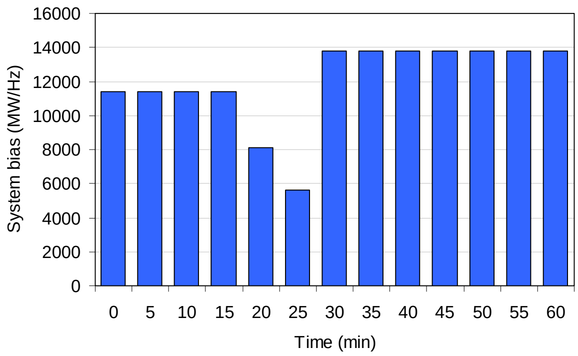

Figure 5 Reduced system bias due to generators reaching rated capacity

2.3 Activation of Secondary Reserve

The means to provide and activate Secondary Reserves varies considerably from one synchronous system to another [5]. AGC functions would change generator output each time step to maintain rated frequency. In the Nordic system, however, AGC is not used and the frequency is allowed to float freely between 49.9 and 50.1 Hz in normal operation [4], [6]. In this paper we show samples from the Nordic system where secondary control is handled manually by activating *Balancing Power* (BP) from the international *Balancing Market* (BM) [2]. This algorithm can be replaced by corresponding AGC functions in the SPF algorithm.

In Figure 3 the frequency drops to just above the minimum requirement of 49.9 Hz before scheduled generation is coming online. If the scheduled generation was delayed another 5 minutes the frequency would drop below this limit and the System Operator would need to act to prevent this. Compared to AGC functions, manual consideration and actions are very difficult to model in a concise way. Four major aspects should be considered:

- The current version of the model has no memory or foresight, and does not "anticipate" a frequency violation before the time step when it actually occurs.
- The operator, on the other hand, will generally observe the trend of the frequency for some time and anticipate the frequency violation before it occurs.
- The required response time of BP in the Nordic system is 15 minutes. No or very little response will be available within the same 5-minute time step as the frequency violation occurs, unless the capacity was called at a previous step.
- The required BP will be delivered partly from units already online, partly by committing new units.

Trying to incorporate all these aspects in "hard code" the following methodology is chosen:

1. When a frequency violation occurs due to gradually increasing demand, the algorithm assumes this was to some extent anticipated by the System Operator,

but activation of BP is not immediate. The amount of BP to activate in the step where a violation occurs is therefore set to *half* of the total amount needed in the *previous* step. The bias is however valid for the present step:

$$\Delta BP(n) = -\Delta f(n-1) \cdot B(n)/2 \ \ (\text{MW}) \qquad (9)$$

2. The required amount of BP is loaded on the cheapest units specified by the user in the BM list (*BalPow* in Figure 2). If the new output exceeds the specified rated capacity, the unit rating is increased accordingly to simulate start-up of another unit. This is possible because the current version uses aggregated generator models, not single unit representation.
3. With the new generation added, the droop response according to Eq. (3)-(8) is re-calculated.

Running a simulation with delayed generation schedule and activation of BP yields the frequency response as shown in Figure 6. The approach can be summarized as follows:

- The model is using droop response only, until a frequency violation is observed (dashed blue line).
- When a frequency violation is observed the model takes one step back, activates BP according to the rules stated above and re-calculates the next time step (solid red line).

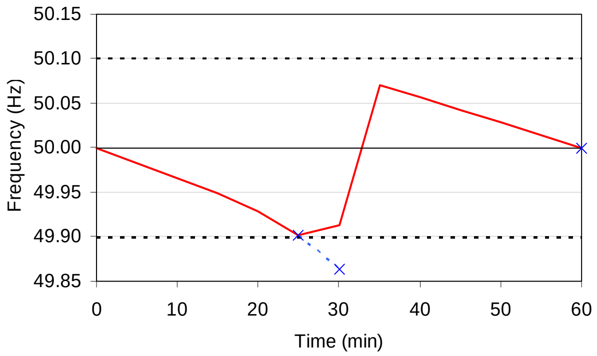

Figure 6 Simulated system frequency with activation of BP

The added BP input to the system will reduce the need for droop control from other units, thus re-establishing some of the system bias as shown by the hatched area in Figure 7.

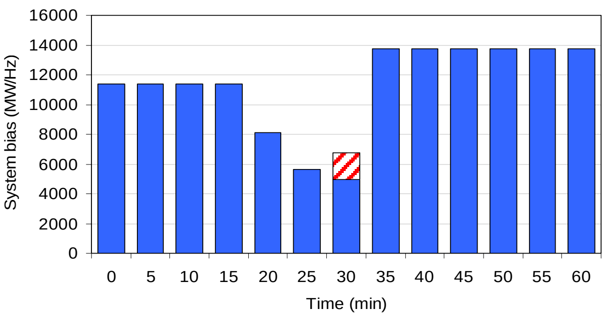

Figure 7 System bias with activation of BP

In the continuation of this work a more sophisticated prediction function will be developed for activation of BP in the Nordic system. In a system using AGC, however, the activation of secondary reserve of Eq. (9) would be replaced by the appropriate Load-Frequency Control equations.

2.4 Generator and load outages

The simulations shown above have been limited to normal operation with intact system. To further stress the system, outages of generators, loads or lines can be added. Any number of outages can in principle be specified by the user at any time step, but caution is recommended. If the powerflow calculation does not converge, the algorithm will fail.

Using the simulation of Figure 3 as basis, a total of P_{out} = 730 MW generation capacity is disconnected at t=10 min. The outage is added to the total system deviation in Eq. (4) before the droop response is calculated, as shown in Figure 2.

Compared to the situation with gradual load increase as described in the previous section, an outage will occur without any warning to the System Operator. The droop response will catch the full impact of the outage, but the response from the System Operator when he calls on Secondary Reserves (from the BM) will again be modeled by Eq. (9). Thus, there will be almost no BP activated in the same 5 minute time step as the fault occurs ($t = T_{out}$) since the frequency deviation of the previous time step ($t = T_{out} - 1$) was very small.

At the next step ($t = T_{out} + 1$), half of the capacity needed in step $t = T_{out}$ is activated etc. As shown in Figure 8 the system is back to “normal” frequency trend 10 minutes after the outage. The dashed blue curve illustrates how the algorithm calculates one step at a time, then goes back to re-calculate if the initial result violates the frequency limit. The solid red curve shows the final droop response. Corresponding changes in system bias are shown in Figure 9.

If a *load outage* was added to this simulation before the scheduled generation increase, this would of course improve the situation by reducing the total system load. If the outages happened after the scheduled load increase (in the next hour) the situation would be inverted; generation outages reducing system stress, load outages increasing the deviation. Such simulations are not shown here.

The frequency deviation due to the outage of 730 MW after 10 minutes is not dramatically large. However, if the outage happened after 20 minutes when the increasing load has already started to influence system bias, the consequences would be more severe as shown in Figure 10 and Figure 11. Again, the dashed blue curve shows the initial droop response and the solid red the resulting frequency. Note that the system bias is dangerously low the first 10 minutes after the outage due to many units operating at rated output.

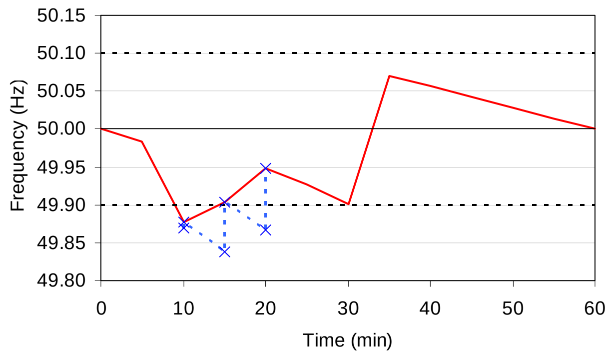

Figure 8 Simulated frequency with 730 MW outage at 10 min.

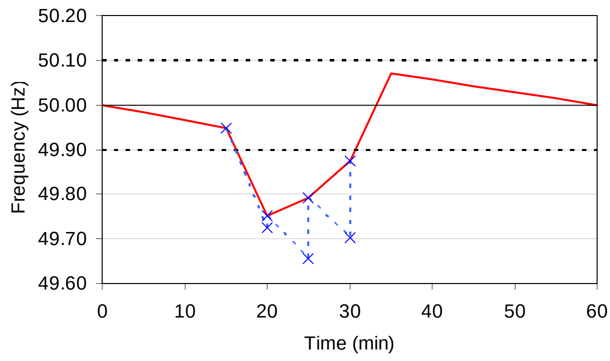

Figure 10 Simulated frequency with 730 MW outage at 20 min.

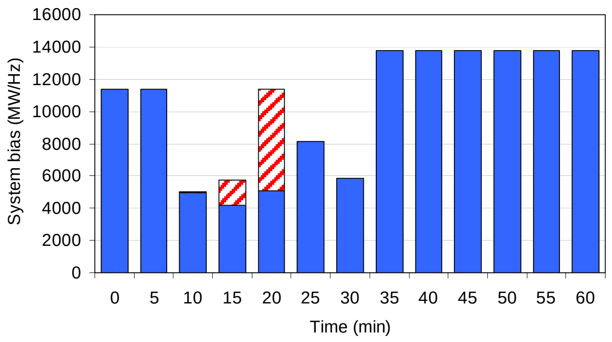

Figure 9 System bias with 730 MW outage at 10 min

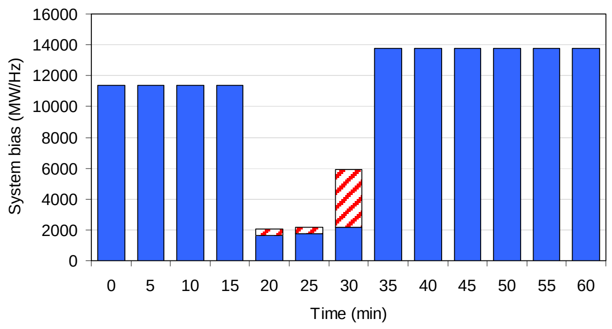

Figure 11 System bias with 730 MW outage at 20 min.

Note also that the two simulations of Figure 8 and Figure 10 show the same outage in the same system with the same load situation. The only difference is *when* the outage occurs within the hour. In the first case, the frequency drops only to a minimum of 49.88 Hz, in the second to 49.75 Hz. This clearly demonstrates the need for these types of analyses in critical load periods.

2.5 Load shedding and generator tripping

Finally, the possibility for load shedding and/or generator tripping is added. Frequency dependent load shedding is an instantaneous function that will give full response in the same time step as the outage occurs. In the algorithm the functions *LdShed* and *GenTrip* are therefore placed between the initial droop response and the activation of BP, see Figure 2.

Currently, it is possible for the user to set two different frequency thresholds for shedding/tripping, and then specify any number of loads/generators at each threshold. When the algorithm is run on an aggregated system model, the MW amount to shed/trip can be any number up to the total load/generation on the specified bus. In the case of the full-scale model described in Section 4, a finite number of generators or loads can be shed.

In this simulation the first threshold for shedding is set as high as 49.80 Hz. This is done mostly to make sure the shedding is activated, but such a level is not unreasonable if loads are supposed to take a more active part as fast reserves [2].

Repeating the same 730 MW outage as in Figure 10, 350 MW load is shed when the frequency drops below 49.80 Hz. The resulting response is shown in Figure 12. As explained, the load shedding is instantaneous and gives a significant contribution to the frequency recovery already in the time step when the outage occurs, bringing the frequency back to almost normal range. The recovery continues in the next time step due to delayed BP activation.

The corresponding system bias is shown in Figure 13. This time, the bias is back to scheduled level within 10 minutes after the outage occurs.

Note that the values of frequency and system bias simulated in this section are not tuned to the real Nordic system. All simulations shown above are made in the simplified 18 bus model, with capacities adjusted to provoke the necessary actions to test and demonstrate the algorithm.

3 LARGE SCALE WIND POWER INTEGRATION

Plans for wind power development in the Nordic countries indicate approximately 10 GW installed capacity within the next 10 years (15% of a peak load of 65 GW) Especially during dry and low-load periods, this capacity is expected to replace existing hydropower, reducing system inertia, bias and reserve capacity.

A study has been made to analyze the impacts of the situation, where the basic SPF algorithm has been further developed to include the following features [7]:

- Multiple synchronous areas
- Ramping of HVDC connections
- Wind generation models

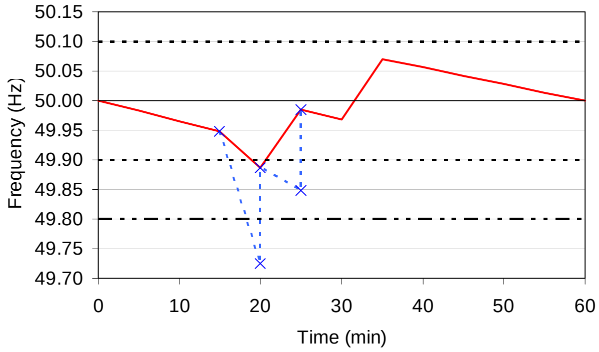

Figure 12 Simulated frequency with 730 MW generation outage followed by 350 MW load shedding

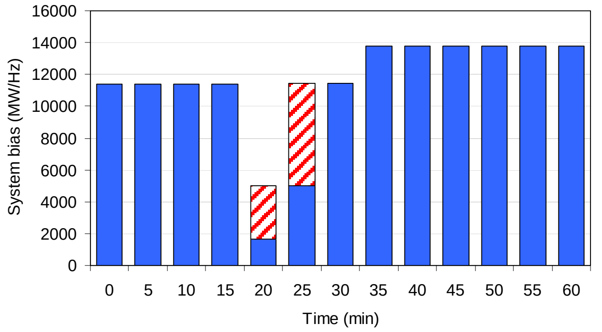

Figure 13 System bias reduction due to 730 MW generation outage followed by 350 MW load shedding

To handle multiple synchronous areas connected by HVDC, the basic SPF algorithm as shown in Figure 2 is run separately for each area, and necessary BP for each area is registered. After all areas are calculated, the reserves are activated from the international Balancing Market. If the cheapest BP resources are located in another area, the HVDC flow between the areas is re-calculated. HVDC dynamics are not explicitly included in the model.

The method of "Moving Block Averaged" with normalized spatial distribution is used to generate aggregated wind farm power input at selected nodes [8]. To study the effect of wind power replacing existing hydro power capacity, wind power is injected at the respective nodes as negative load with a corresponding reduction in existing generation. Furthermore, a load situation with system bias close to the min. value of 6,000 MW/Hz is chosen.

Initial simulations show that it is possible to keep system frequency within normal operating range (+/- 0.10 Hz) when actual wind power output is 20% lower than expected. Assuming that wind power generation does not contribute with BP, this requires activation of large amounts of BP and causes large reductions in system bias as many online hydro power units reach rated output. An outage during such periods could have severe consequences. Large amounts of wind power in the Nordic system might thus necessitate an increase in the requirements for system bias and reserves.

Further studies of large scale wind power integration will be made in the continuation of this work.

4 FULL SCALE MODEL TEST

In order to verify the SPF calculations tests have also been performed on a full scale model of the Nordic system. Load flow data from PSS/E with a total of 4,497 buses, 1,257 generators and 1,636 loads have been converted to MatPower format, and the unit droop settings adjusted to give an approximate level of frequency bias of 15,000 MW/Hz.

Figure 14 shows a comparison between measured frequency from 06:30-07:30 on 23 October 2003 and SPF simulation after tuning of unit droop. The simulation includes pre-activation of 1,040 MW generation at 06:45, but due to operation of HVDC connections, the frequency does not recover quickly at the change of hour. Lacking detailed data of neighboring areas, only the first half of the period is simulated, omitting scheduled generation coming online around 07:00.

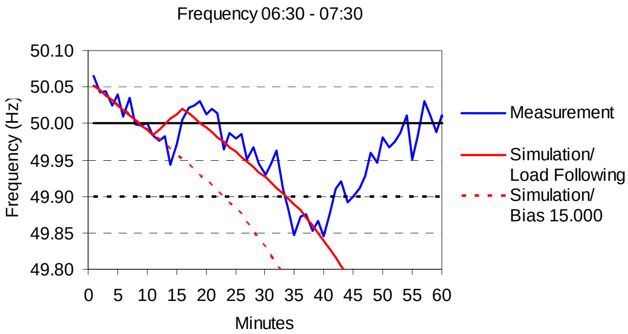

Figure 14 Comparison of measured and simulated frequency response 2003-10-23

Using the adjusted system response as given by the dashed red curve in Figure 14 as basis, test simulations of four different cases are made [2]:

- Case 1: 813 MW outage in Sweden, all BP in Sweden
- Case 2: 813 MW outage in Sweden, all BP in Norway
- Case 3: 818 MW outage in Norway, all BP in Sweden
- Case 4: 818 MW outage in Norway, all BP in Norway

The frequency response is almost identical for all four cases, as shown in Figure 15, indicating that total system losses are not much influenced by the activation of BP. Included for reference in the following figures are the dashed line from Figure 14 and a solid line showing only primary response to the outage ('No BP'). In all cases the outage is almost entirely compensated by activated BP of about 700 MW at t=15. The BP activated at t=25 is mainly due to general load increase.

There are considerable differences in generation response between the cases. Figure 16 shows the total generation in Sweden after an outage in Sweden when all BP is activated in Sweden (Case 1) or in Norway (Case 2), respectively. For Case 1, 705 MW BP is activated at t=15, then 727 MW at t=25. For Case 2, the numbers are 705 MW and 771 MW, respectively. Between these points generation output also increases due to droop response.

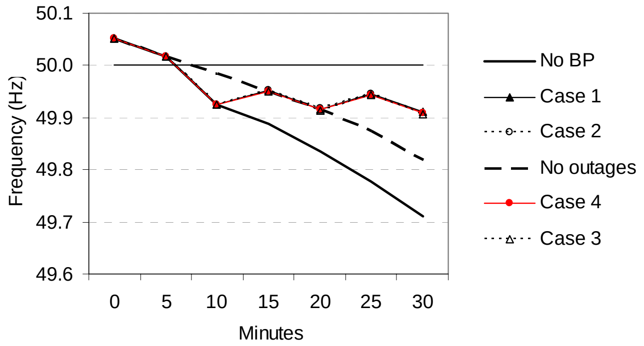

Figure 15 Frequency responses due to outages

If all BP is activated in Sweden, the generation output will increase well past the original load increase. If all BP is activated in Norway, on the other hand, Swedish generation will remain below the original level. The opposite response is found in Norwegian generation for the same two cases, as shown in Figure 17.

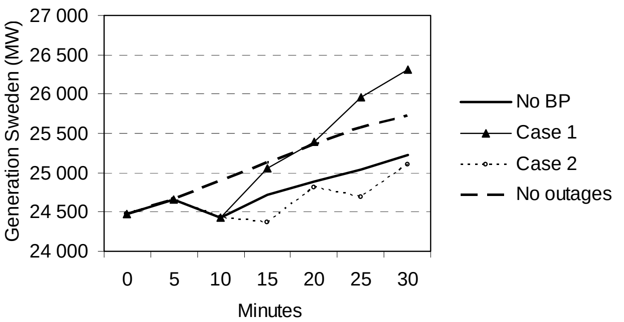

Figure 16 Outage in Sweden: Generation output in Sweden

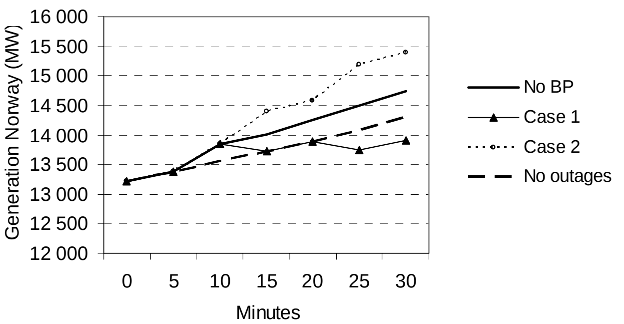

Figure 17 Outage in Sweden: Generation output in Norway

The location of BP has large consequences for the power flow across the important "Hasle" corridor between Norway and Sweden. Originally, there is a flow of 797 MW from Norway to Sweden. With the outage in Sweden without BP the flow is initially increased to 1058 MW due to mutual activation of primary reserves, and further to 1363 MW at t=30. If all BP is activated in Sweden, the flow will be reduced to 808 MW at t=30. If all BP is activated in Norway, on the other hand, the corridor flow will increase more than 1000 MW over the original level.

Should the outage occur in Norway (Cases 3 and 4), an inverse but quite similar response would result. These results are not shown here.

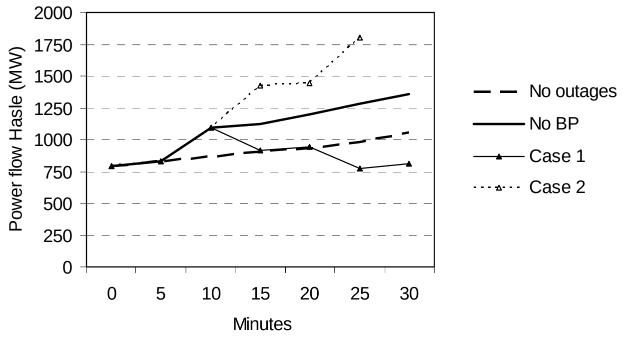

Figure 18 Flow across Hasle corridor when outage in Sweden

5 CONCLUSIONS

In this paper, a new tool named *Stepwise Power Flow* (SPF) has been described, where an AC power flow algorithm is modified to run typically in 5 minute time steps. The tool includes primary (droop) response, activation of secondary reserves and outages as well as frequency dependent generator tripping and load shedding. After being demonstrated on an aggregated 18 bus model of the Nordic power system, the algorithm is tuned and tested on a full-scale Nordic model.

Studies of slow system dynamics during a whole hour show that critical values like system bias and spinning reserve might deviate considerably from the "planning values" used by the System Operator. Furthermore, correlation of line flows, bottlenecks and reserve activation shows the importance of considering reserve location relative to the outage location. The SPF methodology makes it possible for the System Operator to make such assessments in the planning phases.

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