SMART GRID MEASURES TO REDUCE LOSSES IN DISTRIBUTION FEEDERS AND INCREASE CAPACITY TO INTEGRATE LOCAL SMALL HYDRO GENERATION

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ABSTRACT

In Norway the potential for distributed generation is large in many areas with limited network capacity. In order to utilise the existing network and allow as much new distributed generation as possible access to the local grid, it is a need for measures to control the feeder voltage. In many networks there is a considerable increase in reactive power flow as the local generation increases. This paper shows measurements from three sites to illustrate how the reactive consumption increases as the active generation increases. With synchronous generators control of reactive power is easy to implement. This paper shows that a coordinated control of reactive power can be utilised to control feeder voltages within acceptable limits without having to draw large amounts of reactive power from the HV network. By utilising coordinated control it is shown possible to reduce power losses as well as to increase the amount of active power generation an existing network can feed into the power system.

INTRODUCTION

In Norway 1250 hydro power plants generated 96 % of the total electric power generation in 2009 [1]. As much as 920 of them small and medium sized hydro power units defined as distributed generation (DG), with about 6 % of the total generation. The number of DG units is high and rapidly increasing (800 units in 2007). Over 90 % of the power from DG is from about 445 medium sized (1 – 10 MW) hydro units [1], mostly synchronous generators connected to 22 kV overhead lines. Many of them are situated in sparsely populated areas with low load and a network infrastructure adapted to a traditionally low power flow. Distribution networks generally have high resistance, often with R/X ratio between 0.5 and 2, and the feeder voltages strongly depends on the actual power flow and the direction of the power flow. In many cases generation from one single local DG unit exceeds the total local consumption of a feeder. Thus, many DG units, especially when placed at the end of a feeder, have a large influence on the local voltage level.

The minimum voltage is traditionally found at the feeder end when the load is high. When DG units feed power into a network, the voltage in their connection points increase, and when the local generation is high enough and the local load is low enough the voltage in the feeder end exceeds the substation voltage. Due to voltage quality requirements [2], the utilities have to limit the acceptable maximum and minimum voltage in the medium voltage networks.

It has been recommended that all generators should be able to produce rated active power with a unity power factor at any time, independent of local load or other DG units. In many networks, however, the rated power input from one or a few connected generators will cause too high voltage levels in low load situations. In order to be able to use existing overhead lines without violating maximum allowed line voltage some measure to reduce the line voltages is required. There are several ways to avoid too high line voltages due to DG [3, 4], without changing the network. Much used methods are to reduce active power generation, to increase reactive power consumption or to reduce sub-station voltage by tap changing. High reactive power consumption may be a problem for many generators causing them to operate close to stability and protection limits [5]. In addition, an increasing reactive power flow will cause increasing line currents and increasing total power flow. In some cases the reactive power needs to be transported over long distances. Thus increasing reactive power may cause additional losses both in the local distribution network as well as in the transmission network.

Previously all utilities were obliged to give new DG units access to the existing electricity grid only if it was operationally justifiable, but they did not have to reinforce the grid in order to allow connection of new generation units. In January 2010 the Energy Act changed [6] and guarantees all DG units access to the local grid. If needed investments in the networks must be done in order to connect new local generation. With this new grid connection obligation it is expected to be in the interest of both utilities and producers to connect as much generation as possible into an existing network without having to invest in new or reinforce lines or cables. A fit and forget strategy that allows all generators to produce maximum power at unity power factor at any time will not be optimal. Active voltage control actions will be needed to increase the amount of power generation an existing network can handle. With an expected future focus on reduction of network losses, there will be need for coordinated voltage control strategies that do not cause solely large consumption of reactive power.

NETWORK MEASUREMENTS

Measurements from three Norwegian sites are presented:

- **Case I** – Feeder with one synchronous generator producing max. 2.4 MW ~ 16 km from substation.
- **Case II** – Feeder, 57 km, with 8 DG units [7] producing max. 17.8 MW. Maximum 11 MW load. Measurements on a 3.5 MW DG unit 45 km from substation.
- **Case III** – Feeder with several DG units and ~ no load. Ps ≈ -ΣPdg (total generation). Maximum ΣPdg = 6 MW.

Indexs: 's' refers to the sub-station and 'dg' to the dg unit. Power flows, in MW/MVA, are positive into the feeder.

Most small hydro DGs are run-of-river plants with almost no reservoir, and their generation vary according to the varying rainfall and water inflow. Fig. 1–3 show average power flow from substation into the feeder Ps in the three sites over two or three years. Here it is shown how Ps is bidirectional and varies considerably over the year. Case III (Fig. 3) shows a common pattern with highest generation in summer/autumn and low generation during the winter (high load). In [7] it was shown how all several units connected to the same feeder show almost the same variations, resulting in max./min. power from all units at almost the same time. A few DG units have some reservoir (like Gen. 5 in Fig. 5), allowing them to shift some production to periods when the other DGs run with lower power, but not enough to enable them to run at rated power hundred percent of the time.

Fig. 4 shows a typical example of how a DG unit consumes reactive power and causes an increase in feeder reactive power flow when the DG unit produces active power. Fig. 4 also shows how the voltage in the sub-station (Us) and in the DG connection point (Udg) varies considerably due to variations in DG power and feeder load.

The measurements show that the reactive power flow increases substantially with increasing local generation (Fig. 1-Fig. 5). Fig. 6 shows duration curves for measured local generation. The duration of the high generation varies from only 84 hours with total generation above 16 MW in Case II to 1440 hours of full generation in Case I. In Fig. 5 for Case III, it is shown how the duration of high production can vary from one year to the next.

Measurements also show that in most cases the production is low when the load is high, e.g. Fig. 6 Case I. In periods with maximum production the load is low or medium.

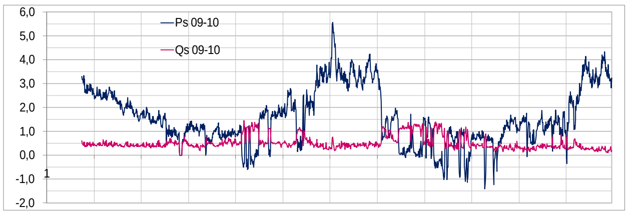

Fig. 1. Substation Qs (pink) & Ps (blue). Case I. 2009-10.

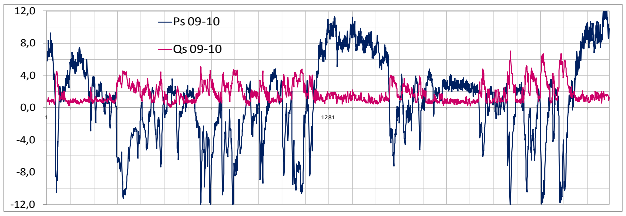

Fig. 2. Substation Ps (blue) & Qs (red), Case II. 2009-10.

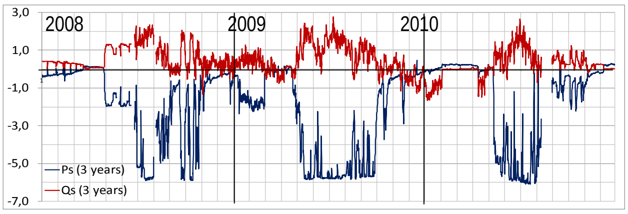

Fig. 3. Substation Qs (red) & Ps (blue) Case III. 2008-10.

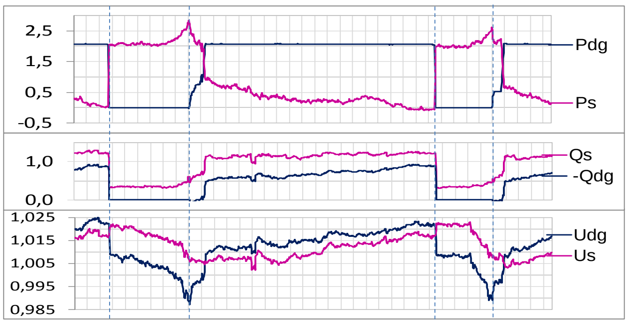

Fig. 4. Measured Ps, Qs, Us (sub-station) & Pdg, Qdg, Udg (DG unit). Case II. 37 hours (April 2010). Ubase=22kV.

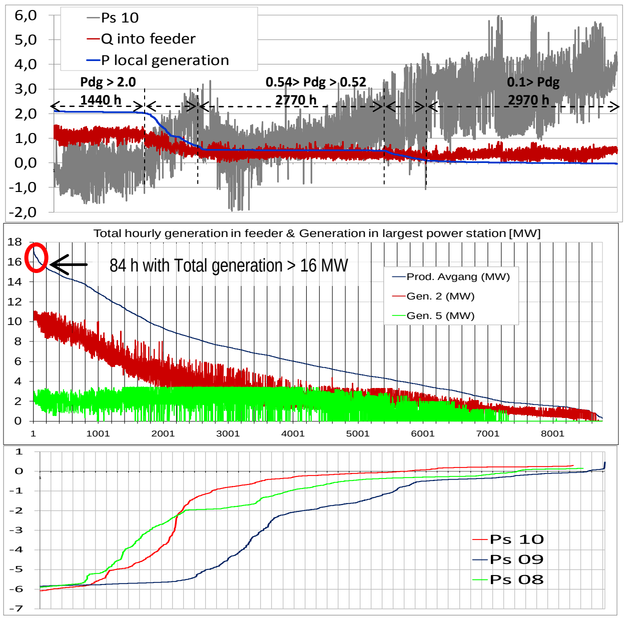

Fig. 5 Duration curves for total feeder generation in the three cases I (upper), II & III (lower).

ANALYSES WITH SIMPLIFIED CASES

Two simplified feeder Cases I' and II' have been analysed. They resemble the measured cases except that two planned DG units are included in Case I'. Data is presented in Tab. 1 and appendix Fig. A1-A2. DG and load powers are referred to the MV side of the transformers. In average all loads are assumed to be voltage independent, causing the feeder losses to decrease with increasing voltage. Substation voltage is 22 kV to simplify the analysis. Low load (LL) or low production (LP) equals 25 % of high load (HL) or full production (FP). Medium load/production (ML/MP) equals 50 % of HL/FP. Focus is on these three variables:

- The maximum/minimum voltage at the end of the feeder
- The power flow into/out of the feeder, Ss (or Ps & Qs)
- The power losses of the MV feeder lines (Ploss)

Tab. 1 Summary of data for Case I' and Case II'.

Case:	High load	Full prod.	Feeder length (& dimensions)
Case I'	4.1 MW	11 MW	20 km ($^1/_4$ FeAl 120 & $^3/_4$ FeAl 25)
Case II'	12.5 MW	18 MW	50 km ($^1/_2$ FeAl 120 & $^1/_2$ FeAl 50)

Tab. 2 Low load and full production in Case I' and II'.

Case:	Case I'			Case II'		
Control:	Qs=0	Qdg=0	Qdg<0	Qs=0	Qdg=0	Qdg3<0
Max. voltage rise	+4.1 %	+4.9 %	+2.7 %	+4.9 %	+8.5 %	+3.9 %
Ss (MVA)	9.7	9.7	10.8	13.9	14.2	14.5
Qs (MVAr)	0	0.5	5.0	0	2.6	4.4
Ploss (kW)	282	270	339	978	932	1028

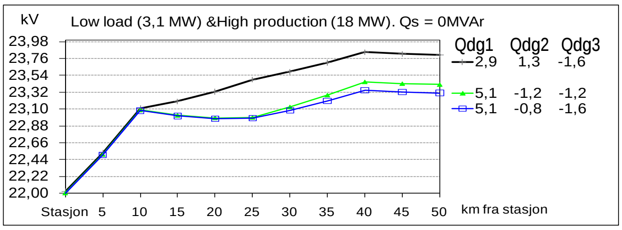

Fig. 6. Voltage along feeder, Case II. LL & FP with Qs=0.

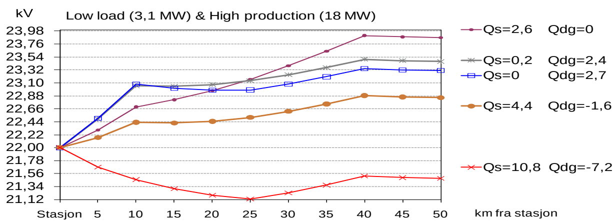

Fig. 7. Voltage along feeder, Case II. LL & FP.

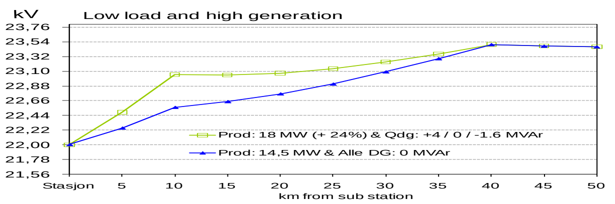

Fig. 8 Feeder voltages in LL & high generation. Case II'.

Tab. 3 Low production situations.

	HL & LP			ML & LP		
Case I':	Qs=0	Qdg=0	Qdg<0	Qs=0	Qdg=0	Qdg<0
Max. voltage rise	+4.2 %	+4.0 %	+1.8 %	-0.2 %	-0.3%	-0.9 %
Ss (MVA)	8.7	8.8	10.1	0.7	0.7	0.8
Qs (MVAr)	0	0.6	5.1	0	0.4	1.5
Ploss (kW)	221	222	296	4	5	11
Case II':	Qs=0	Qdg=0		Qs=0	Qdg=0	Qdg3<0
Max. voltage rise	-6.6 %	-10.9 %	-	-1.5 %	-3.2 %	-4.4 %
Ss (MVA)	8.3	9.0	-	1.8	2.2	2.5
Qs (MVAr)	0	3.3	-	0	1.3	1.7
Ploss (kW)	310	362	-	19	26	38

COORDINATED VOLTAGE CONTROL

Coordinated reactive power control is previously [7] shown suited to keep line voltages low in critical LL & no production (NP) situation without causing a large flow of reactive power into a feeder due to DGs consuming reactive power. An easy way to do this is to let DG unit(s) at the end of a feeder consume reactive power to keep the local voltage below the maximum limit, and to let DG unit(s) close to the substation produce reactive power and keep reactive power flow into the feeder (Qs) low or preferably equal to zero. Fig. 6 shows that even if this simple strategy manage to keep Qs=0, there will be more optimal distributions of Qdg that will minimise the feeder voltages (or the power losses in other situations).

Tab. 2 shows data for alternative LL & FP situations. For Case II' Fig. 7 shows that operating all generators at unity power factor (Qdg=0) gives too high voltages to be an alternative operation. Thus, keeping Qs=0 is an alternative to let DG3 consume reactive power (Qs=4.4 & Qdg=-1.6) or to let all DG units (Qs=10.8 & Qdg=-7.2) consume reactive power. Compared to this second alternative, the coordinated control (Qs=0) in Case II' reduces feeder flow with 20 % and losses with 30 %. A more realistic alternative in Case II' will be let only DG3 consume reactive power. Compared to this situation the coordinated control will reduce the feeder flow with 4.3 % and the losses with 4.9 %, but the voltage will increase from (+3.9 % to +4.9 %). For Case I' the coordinated control reduces the power flow with 11 % and the losses with 17 % compared to a situation with tan φ=0.4 for all DG units (Qdg<0).

Compared to operation with Qdg=0 the coordinated control does not reduce feeder flow or losses much in LL & FP situations, and its benefit will mainly be reduced feeder voltages. Fig. 8 shows that maximum feeder voltage in Case II' is the same with 14.5 MW generation and unity power factor (Qs=1.8MVAr) as with 24 % higher generation (18 MW) with a simple coordinated control (Qs=0.2MVA) involving only DG1 (4MVA) and DG3 (-1.6 MVA).

Coordinated reactive power control can also be used to reduce power losses in situations when the voltage levels are not the limiting factor as shown in Tab. 3. Especially at ML & HL with low production it is possible for local DG units to produce reactive power enough to cover the local demand and lift the feeder voltages. This may reduce the power flow and the feeder losses considerably. Compared to Qdg=0 the Qs=0 control in ML & LP reduces flow and losses by respectively 14 % and 8 % in Case I' and 20 % and 29 % in Case II'. For the HL & LP situation the flow and losses are reduced with 15 % and 13 % in Case I' and with 8 % and 15 % in Case II'. Both these situations are very frequently occurring. The effect is considerably larger if comparing with the very realistic situation with Qdg3 consuming reactive power (tanφ=0.4).

DISCUSSION

This paper uses simple calculations to illustrate the effect of coordinated control. Simulations of a limited number of operation cases, using detailed network data for Case II, show the same effects [7]. System stability analysis and dynamic responses to severe disturbances has been studied using detailed network data [8]. These analyses showed no instability problems, but not all post-disturbance generator terminal voltages and power factors were within the normal range. This needs to be investigated further since situations causing unnecessary protection action and disconnection of generators are not wanted. The effect the suggested control has on tap changing frequency also needs to be looked into.

In this paper it is focused on the reduction of losses only in the actual MV feeder. In most practical networks reduction of reactive power flow into a feeder will also give a considerable loss reduction in the transmission network due to reduced power flow and in the low voltage network due to a generally higher voltage level. Whether active control is profitable depends on the actual increase in power transfer, the total loss reduction and on the need for investments. Coordinated control requires generators that are able to operate with required tanφ, as well as suitable equipment for remote voltage control and communication. For such an active control to be successful it needs a robust control strategy that is suitable for all possible operation situations, including constantly changing production and load. Care has to be taken in order to avoid generator stability problems. A field demonstration is up for discussion.

CONCLUSIONS

Presented field measurements illustrate aspects that are common for many feeders with substantial amount of DG:

- Power generated varies frequently.
- Power generated varies (with river flows) over the year.
- Power generation does not follow local load demand.
- Reactive power flow increases with local generation.
- Feeder voltages vary strongly with load and generation.

With synchronous generators voltage control is relatively easy. This possibility is, as shown, used in many networks to reduce line voltages. This strategy results in a large reactive power flow into the feeder and increased network losses. This paper shows that coordinated control of reactive power is a suitable method to keep maximum feeder voltages within their limits in critical low load high generation situations, and thus to increase the maximum amount of active power a weak network can transport out of an area. With this voltage control possibility present, it should also be utilised to reduce power losses whenever there are any generators connected. This loss reduction will be largest in high and medium load situations with low production.

Acknowledgments

These results have been obtained in the SINTEF-project "Distribution 2020" supported by The Norwegian Research Council, ABB, Hafslund, Agder Energi, Helgelandskraft, Trondheim Energi and NTE, Siemens, Nortroll and the Norwegian regulator. Measurements have been performed by SINTEF in cooperation with several utilities and the project is very grateful for being able to use them.

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APPENDIX – ANALYSED SIMPLIFIED FEEDERS

Lines are represented by resistance and inductance only.

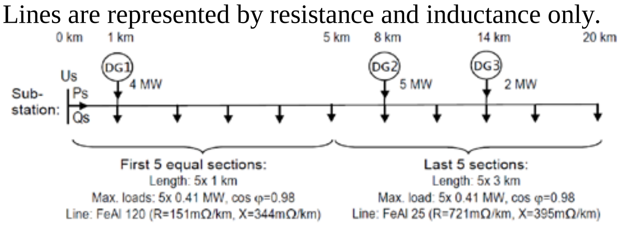

Fig. A1. Feeder used to represent Case I.

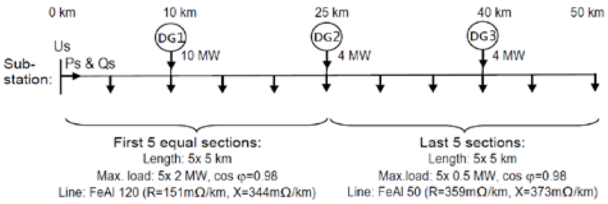

Fig. A2. Feeder used to represent Case II.