Ancillary services from distributed energy resources – perspectives for the Danish power system

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Abstract. The share of the electric power production originating from distributed energy resources has rapidly increased during the recent past. However when it comes to ancillary services necessary to ensure the stability and appropriate operation of the power system, the distributed energy resources take a very passive role.

This paper outlines suggestions on how to activate the potential of ancillary services from distributed energy resources, thereby exploiting their ability to contribute to power system operation. Furthermore, methods for integrating the ancillary service delivery into a deregulated power system are proposed and evaluated.

Keywords

Distributed energy resources, ancillary services, deregulation.

1. Introduction

During the past two decades the propagation of distributed energy resources (mainly wind turbines and local combined heat and power plants) in the Danish power system has increased from being negligible to represent above 40% (2005) of the total electric power consumption [1].

Traditionally, the central power plants deliver not only the electric power but also a set of ancillary services to support the power system operators in their effort to keep the power system in a secure and appropriate state of operation.

Since the electric energy delivered by central power plants is being increasingly displaced by the distributed generation, whilst the central power plants are still needed to supply ancillary services, the central power plants are often forced to operate in a non-ideal mode, leading to reduced efficiency and increased economical costs of these plants.

To provide a real alternative to the central plants and allow a migration to a truly distributed power system, the distributed energy resources must contribute to the power system operation by providing the same set of ancillary services as the central plants.

In a deregulated power system the providers of ancillary services must deliver their services on market terms or by tender in order to achieve an economically optimal dispatching of the services. It means that financial mechanisms must be established that allow central as well as distributed resources to provide their services in competition with one another.

2. Distributed generation in The Danish power system

The Danish power system is divided in two separate synchronous areas, the western (DK1) being part of the European *UCTE* area and the eastern (DK2) being part of the Nordic *Nordel* area. In Fig. 1 a map of Denmark with the two areas indicated is shown. There is currently no direct link between the two parts of the system, but HVDC connections from DK1 to Norway and Sweden and from DK2 to Germany, make energy transfers possible. Furthermore a direct HVDC link between DK1 and DK2 is planned.

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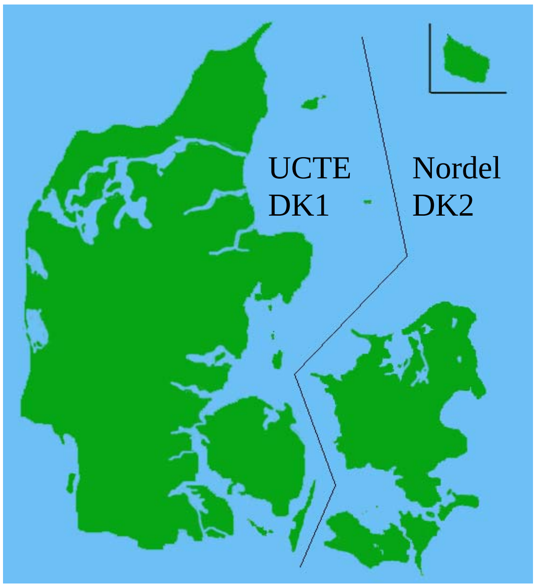

Fig. 1. Map of Denmark and the synchronous systems

In Table I an overview of peak loads and installed production capacity for the areas is given. It is clear that in the DK1, the propagation of distributed generation is much more extended than in DK2. For the wind turbines it is caused by the wind potential being much higher along the western shore, and for the decentralized CHP plants it is caused by the large number of villages in DK1, suitable for district heating.

TABLE I
CAPACITY AND DEMAND IN THE DANISH POWER SYSTEM

	DK1 / West	DK2 / East
Peak load	~3,650 MW	~2,700 MW
Central power plants	4,057 MW	4,328 MW
Decentralized CHP plants	1,124 MW	399 MW
Wind turbines	2,393 MW	735 MW

Peak loads are typical winter day peaks. All figures are 2005 values [2]-[4].

Because most of the currently installed wind turbines are of the "Danish concept" type, i.e. equipped with a directly grid-connected induction generator with poor or no control opportunities, they are not capable of supplying ancillary services. However, since any new installation must comply with the latest grid codes, including active and reactive power control, there may be a potential for ancillary services from wind turbines in the future.

In contrast, the decentralized CHP plants are most commonly equipped with synchronous generators, driven by gas engines (piston engines) or gas turbines, making them very flexible and suitable for providing ancillary services.

In Table II an overview of the decentralized CHP production capacity is given, grouped by size. The lower limit of 1.5 MW is chosen because the transmission system operator Energinet.dk has different grid codes for plants above or below 1.5 MW [5].

The figures show that in DK1 the largest capacity is represented by small and medium-sized plants (< 25 MW) whereas most of the capacity in DK2 is concentrated on a few larger plants (> 25 MW).

TABLE II
DECENTRALIZED CHP PLANTS IN DENMARK

Plant capacity	DK1 / West		DK2 / East	
< 1.5 MW	96	87 MW	12	9 MW
1.5 MW – 10 MW	126	481 MW	21	73 MW
10 MW – 25 MW	15	223 MW	6	72 MW
> 25 MW	6	333 MW	5	244 MW

Figures by October 1, 2005 [2]. Capacities are electric power capacities. Aggregated values are expressed as number of plants as well as aggregated production capacity.

3. Ancillary services

This section provides an overview of some ancillary services currently requested by transmission or distribution system operators. The separate areas DK1 and DK2 must each be operated in compliance with the neighbouring systems they are part of, specified in the *UCTE Operational Handbook* [6] and the *Nordel System Operation Agreement* [7], respectively.

Due to these constraints the conditions for some of the ancillary services are slightly different in the two systems, however the fundamental principles and the applicability to distributed resources are the same.

A. Frequency controlled reserves (Primary control)

In a situation where an imbalance between generation and load results in a deviation of the system frequency from the nominal frequency, the primary control action is to adjust the power generation based on a local measurement of the actual frequency.

This is implemented as a proportional controller at each generator, often referred to as a droop controller. In Fig. 2 the relation between frequency deviation and control action for a droop controller is shown.

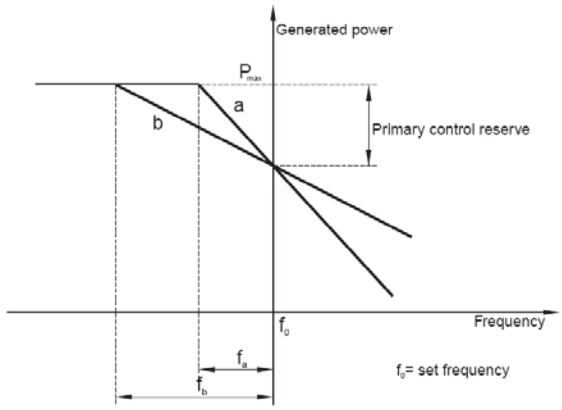

Fig. 2. Sketch of two different droop controller characteristics [6]

1) Requirements

In DK1, the frequency controlled reserves must supply a total of 32.1 MW upward or downward regulation, calculated as a relative fraction of the entire UCTE area, which requires 3,000 MW primary control reserves. The control response must be delivered linearly with a frequency deviation of 0.2 Hz, within 15 seconds for a 50% response and within 30 seconds for a 100% response [6].

In DK2 there are two different kinds of frequency controlled reserves: The *frequency controlled normal operating reserve* and the *frequency controlled disturbance reserve* [7]. The *normal operating reserve* is for maintaining the system frequency at a reasonable level during normal operation, i.e. to compensate for minor deviations in the expected production or consumption. It must be fully activated at a frequency deviation of 0.1 Hz, with a maximum time delay of 2-3 minutes. DK2 is obliged to provide ± 23 MW regulation for this purpose, out of a total requirement for the Nordel area of ± 600 MW.

The *frequency controlled disturbance reserve* must compensate for any sudden loss of production, and it is therefore only an upward regulation. It must be delivered linearly with a frequency drop between 0.1 Hz and 0.5 Hz, with a maximum time delay of 5 seconds for 50% of the required control response and 30 seconds for the total response. Automatic frequency dependant load shedding may be considered a disturbance reserve. The Danish system must supply 153 MW of frequency controlled disturbance reserve to the Nordic system, which in total requires 1,020 MW. In Fig. 3 the control responses of the two kinds of frequency controlled reserves are illustrated.

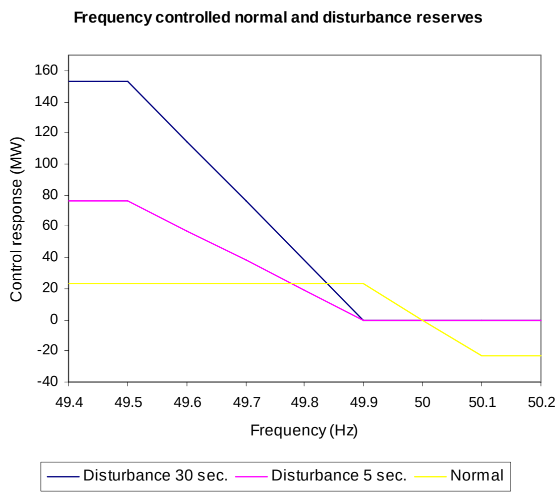

Fig. 3. Illustration of the control responses from frequency controlled normal and disturbance reserves.

2) Implementation

Since the primary control response must be delivered within seconds, it is usually provided by spinning reserves, i.e. power plants that are operating below their maximum capacity and thereby reserve power for primary control. Distributed generators however, are very often operated intermittently and are therefore traditionally not considered suitable for primary control. In order to utilize the potential of primary control resources of the distributed generators, measures must therefore be taken in the management systems to assure that the necessary capacity is present at any time. It means that communication with each generating must be established in order to control and monitor which generators currently take part in the primary control.

3) Suitable distributed generators

In [8] the possible utilization of primary control reserves from distributed generators equipped with a power electronics interface (inverter) is investigated. These generating units could be modern wind turbines, fuel cells or micro turbines. It is concluded that it is possible to use these resources for primary frequency control. Even wind turbines can contribute in the short-term by extracting kinetic energy from the rotor as a reserve. This is possible since there is no coupling between rotor speed and grid frequency as in conventional generators.

However with the current state of the Danish power system, this kind of resource is – though increasingly propagated – still rare. The decentralized CHP units with synchronous generators driven by gas engines are common and have a fast response. In DK1 there is a total CHP capacity (neglecting plants below 1.5 MW) of 1.037 MW (table II) and the required primary control response is 32.1 MW. It means that every plant would have to reserve 3.1 % of their capacity for primary control if they were all running at the same time. Since that is not the case the relative capacity each plant would have to reserve would be significantly higher. An important issue is the ability of the plant to satisfy the heat demand if the electric power output is limited. It depends very much on the specific plant and the current operating conditions.

B. Non frequency controlled reserves (Secondary and tertiary control)

Due to the characteristics of the primary frequency control, additional control actions must take place in order to compensate the steady-state error from the droop control. These reserves are not directly frequency controlled and may be activated automatically or manually due to several reasons, including:

- primary control being close to its limit
- power exchange with neighbouring power systems exceeding acceptable limits
- the integral of the frequency deviation exceeding acceptable limits

1) Requirements

The terminology is a bit different in the areas DK1 and DK2. In DK1 the secondary control is automatically operated by a central AGC controller established at the system operator Energinet.dk. The reserves activated by this controller are hence called *automatic regulating reserves.* The control response must start within 30 seconds after the activation signal has been send, and must from that point increase with a gradient of at least 30% of the total response per minute. In Fig. 4 the control response from the automatic regulating reserves is shown. A total of ± 140 MW is currently reserved for automatic regulation.

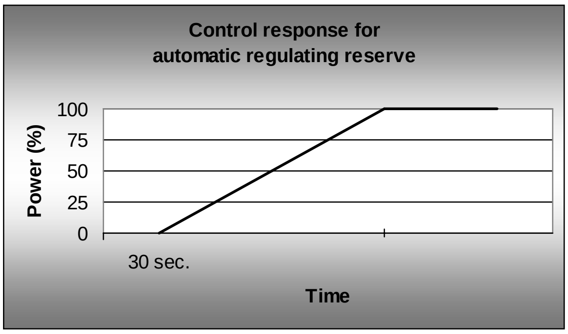

Fig. 4. Illustration of the control responses from automatic regulating reserves [9].

The tertiary control is activated manually by the system operator and the reserves are therefore called *manual regulation reserves.* There must be a maximum time delay of 15 minutes from the request from the control centre has been sent to the reserve is fully activated. A total of +630 MW / –160 MW is currently reserved for manual regulation.

In DK2 the manual reserves are divided into the *fast active forecast reserve*, the *fast active disturbance reserve*, the *fast active counter trading reserve* and the *slow active disturbance reserve*. The fast reserves must deliver their full response within 15 minutes from initiation. For the slow reserves the time limit can be 60 or 90 minutes.

2) Implementation

Dependant of the required time frame for the control response it may be provided by spinning or stand-by reserves. The stand-by reserves are already being commonly provided by CHP plants; however the potential for distributed resources acting as the faster responding spinning reserves has not yet been exploited. As for primary control it must be assured that the required capacity is present at any time and the similar considerations about fulfilling the heat demand must be made if a fraction of the production capacity is reserved for later activation.

C. Reactive power and voltage control

Reactive power balancing and voltage control in distribution grids is attracting increasing attention from the distribution grid operators as distributed energy resources are propagated in the grid. Traditionally, the lines were dimensioned so that a voltage near the upper limit at the transformer would give a voltage near the lower limit at the end of feeders. However when distributed generators feed into the system, the voltage profiles are no longer simply predicted. A continuous voltage control through reactive power balancing and tap changer operation must take place in order to keep the voltage within acceptable limits.

Furthermore the system operator Energinet.dk has introduced limitations in the allowed exchange of reactive power between the transmission system and distribution grids (the so-called *Mvar-arrangement*), meaning that distribution grid operators must compensate the reactive power within the distribution grid to a larger extent.

In [10] a comprehensive analysis of reactive power flows, sources and sinks within a typical distribution grid in DK1 is made. The grid is highly influenced by the presence of directly connected induction generator wind turbines, consuming a large amount of reactive power in windy conditions. On the other hand, since most lines below 100 kV have been converted to cables, a significant reactive power source is inherently present within the grid itself, leading to reactive power surplus in low load conditions. Both issues call for flexible reactive power resources in order to balance the reactive power within the grid.

Additionally, from the point of view of the transmission system operator, a properly controlled distribution grid including its attached generators may act as an aggregated reactive power compensator providing voltage control on the transmission grid, thus saving investments in other reactive power compensators, such as reactors or FACTS devices.

1) Implementation

For reactive power the physical location of the source or sink is of great importance since reactive power transfer over long distances is undesired due to the resulting voltage drops. This makes the distributed resources very well suited for local reactive power balancing within distribution grids.

Distributed resources equipped with synchronous generators or power inverters are capable of balancing reactive power. Particularly, the ability of the latter to absorb reactive power is very attractive for distribution grid operators, due to the problem with surplus reactive power in low load conditions.

The control system must manage the reactive power resources and the tap changers coordinated so that the desired voltage profile is obtained. Local voltage control at e.g. CHP plants may lead to unwanted automatic tap changer operations.

Another important issue when changing the reactive power output from a CHP with a synchronous generator is the angle stability margin. If the generator is under-excited to absorb reactive power the rotor angle related to the stator field is increased, meaning that the stability margin is decreased. The acceptable limit depends very much on the actual location and grid conditions of the plant, so an individual assessment must be made if the full potential should be utilized.

D. Black start capability

In order to black start the power system after a complete break-down, a few plants attached to the transmission grid must be able to start without external voltage supply and energize the transmission grid. Their capacity should be sufficient to allow the central plants to start and eventually provide the power for loads.

Distributed resources are often capable of black-starting themselves or require very little additional power supply during start-up. It means that the resources within a distribution grid may be started with a relatively small energy storage and finally energize the transmission grid. As for any black start situation, coordination is of great importance when initiating the distributed generators.

4. Financial mechanisms

In order to utilize the potential of any provider of ancillary services in an economically feasible way, proper financial mechanisms must be established to assure a deregulated competition between individual providers. Such mechanisms can be market places or tender invitations and negotiations.

Literature provides several examples of ancillary services markets. An example is [11], in which a review of existing ancillary service management and markets is made, as well as suggestions for new market structures for the ancillary services: Voltage control/reactive power, spinning reserves and frequency control. Regarding the reactive power problem, which is mainly a local problem, a national or even international market price is not suitable. For this purpose the concept of voltage control areas in introduced to handle the local effects of reactive power support.

One important issue of reactive power support is the assessment of the costs. Since reactive power does not carry energy, there is no natural additional expense for a CHP to provide it, as for real power that requires additional fuel. However the supply or consumption of reactive power from the synchronous generator can result in a reduced maximum real power output, meaning a loss of income opportunity, which must be reasonably compensated. In [12], new concepts of reactive power pricing are introduced and evaluated that are applicable for various market types.

An example of a well functioning ancillary service market with participation from distributed generation is the market for manual reserves in DK1. This a monthly auction, in which power plants and CHP plants can place bids of at least 10 MW reserve. Since most CHP plants do not have 10 MW of production capacity they are aggregated by the *production balance responsible entities*, which also handle the actual activation of the reserve if relevant. If the reserve is activated the payment for the energy is handled by the Nordic market for regulating power.

This mechanism also illustrates the benefit of aggregation. As the number of markets that are open for distributed generation rises, the decision on how to optimize the plant operation and income gets similarly harder. The plant operators gain from aggregation by having an aggregating entity administrate the trading of power and ancillary services from the plant. On the other hand the system and grid operators gain from a simplified interface to the resources. As the distributed generation in the future possibly moves towards even smaller units like micro-CHP units or domestic photovoltaic systems, aggregation gets even more important from the point of view of system operators.

5. Conclusion

Utilizing the potential of distributed energy resources as providers of ancillary services will increase the flexibility of the power system and support secure operation. If proper control and management systems are incorporated, the distributed resources are capable of providing a set of ancillary services, which eventually enables the distributed resources to compete with traditional central power plants on deregulated market conditions. As the size of distributed generation units tends to decrease, aggregation gets increasingly important for market participation and control options from the system operator point of view.

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