Market Access for Smaller Size Intelligent Electricity Generation (MASSIG)

Delivery 6.3

Present market options for small DG

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Abstract:
In the EU-project MASSIG, http://www.iee-massig.eu/, an important goal is to promote and increase the participation of small scale power producers in the electricity markets, e.g. the Spot market and the electricity balancing markets.
In this Delivery 6.3 are described some present market options for small scale intelligent generators in Denmark, Germany, Poland and UK, that already today are available for small scale power producers.

Contents

1 Introduction

Especially in energy systems with large amounts of fluctuating renewable energy productions it is important that all intelligent electricity generation participates in the integration of these fluctuating productions. Distributed small scale power producers are becoming a bigger part of the electricity supply; therefore it becomes more and more important that they also deliver intelligent generation through e.g. the Spot market and the balancing markets.

After the EU-Directive 96/92/EC went into force in 2001 EU-Member States had to gradually liberalize their power markets. As a consequence market places for the trade of electricity emerged, that offer trade of a variety of power products on different times scales. In the following, markets and products typically offered by power exchanges (PXs) and their relevance for market actors is briefly described:

- Long-term trade:
  Power producers as well as large consumers or retailers prefer to sell/buy power some time in advance because they do not like to be exposed to the risk related to short-term variations of the power price. If you are an operator of a power plant with certain variable cost you would prefer to find a retailer who buys your power for the next calendar year at a price which at least equals your cost rather than to sell it on a daily basis at an uncertain price. The retailer will prefer this option as well because his revenue is bound to the tariff he offers to consumers. To match these needs power exchanges offer trade of yearly, quarterly, monthly and weekly power products so called Power Futures. In order to make the products tradable they have to be standardized in terms of amount, time of delivery and price. PXs typically offer base (continuous power delivery) and peak products (e.g. continuous delivery between 8 a.m. and 8 p.m. on working days).
- Day-ahead auction:
  A wind power producer can in the long term only estimate the average production and sell it e.g. in form of monthly baseload products. The actual generation will however largely deviate from this average value and therefore he needs an opportunity to trade deviations between short-term forecasts (e.g. day-ahead) and the amount contracted in the long-term. As consumption is also to some extent uncertain and the daily profile typically cannot be matched with base and peak products only, also a retailer needs to trade power in the short-term. The PX therefore offers day-ahead auctions where hourly or block products can be traded for the following day.
- Intra-day market:
  If a wind power producer updates his forecasts with latest weather data and finds significant deviations from day-ahead forecasts he will like to trade differences in the short-term. The same need occurs for a power plant operator facing an outage. An increasing number of PXs therefore offer intra-day markets. They may be either organized in form of periodic auctions (each 3 hours) or in form of continuous trade (matching offers and bids are cleared immediately). Offers and bids can be submitted until few hours before physical delivery. An intra-day market is especially important for wind power given the high intra-day variability.

Power can in most countries also be traded bilaterally. In this case volume, price and time of delivery are subject to negotiation. The price on the PX acts as a reference value for bilateral interactions.

As electricity cannot be stored, in each instant supply must equal demand. It is however not possible to establish this power balance through a conventional market because actors would have to trade on a second per second basis. Therefore deviations between scheduled (traded) supply and demand are balanced by a third party – the so called System Operator (SO). In order to fulfill this task the SO purchases so called power reserves being activated when needed: When there is a lack of power so called upward-regulation is activated and in the case of excess power so called downward regulation is activated.
To balance the system different types of reserves are needed:

- Primary reserve:
  Primary reserves react immediately on imbalances to stabilize the system. A power plant or load offering primary reserve has to quickly up- and downward regulate. The activation is directly related to the frequency of the power system. If it exceeds the nominal value of 50Hz primary reserves downward regulate and vice versa. Primary reserves are shared among countries with interconnected power systems – e.g. a power plant outage in Germany is compensated by primary regulation in all countries belonging to the so called UCTE-system.
- Secondary reserve:
  The task of secondary control is to re-establish the local power balance. To compensate for the outage upward regulation will be activated in Germany and primary reserves in the UCTE area restored. Secondary control is activated automatically within few minutes and therefore requires dynamic changes of power output and demand respectively.
- Tertiary reserve:
  In order to restore the activated secondary control, so called tertiary control (also indicated as Minutenreserve) is activated manually. The offered amount of Minutenreserve typically has to be activated within 15 min. This type of reserve can therefore also be offered by fast starting power plants.

The following figure illustrates the time-scales on which different reserves act exemplarily for the case of the Danish power market.

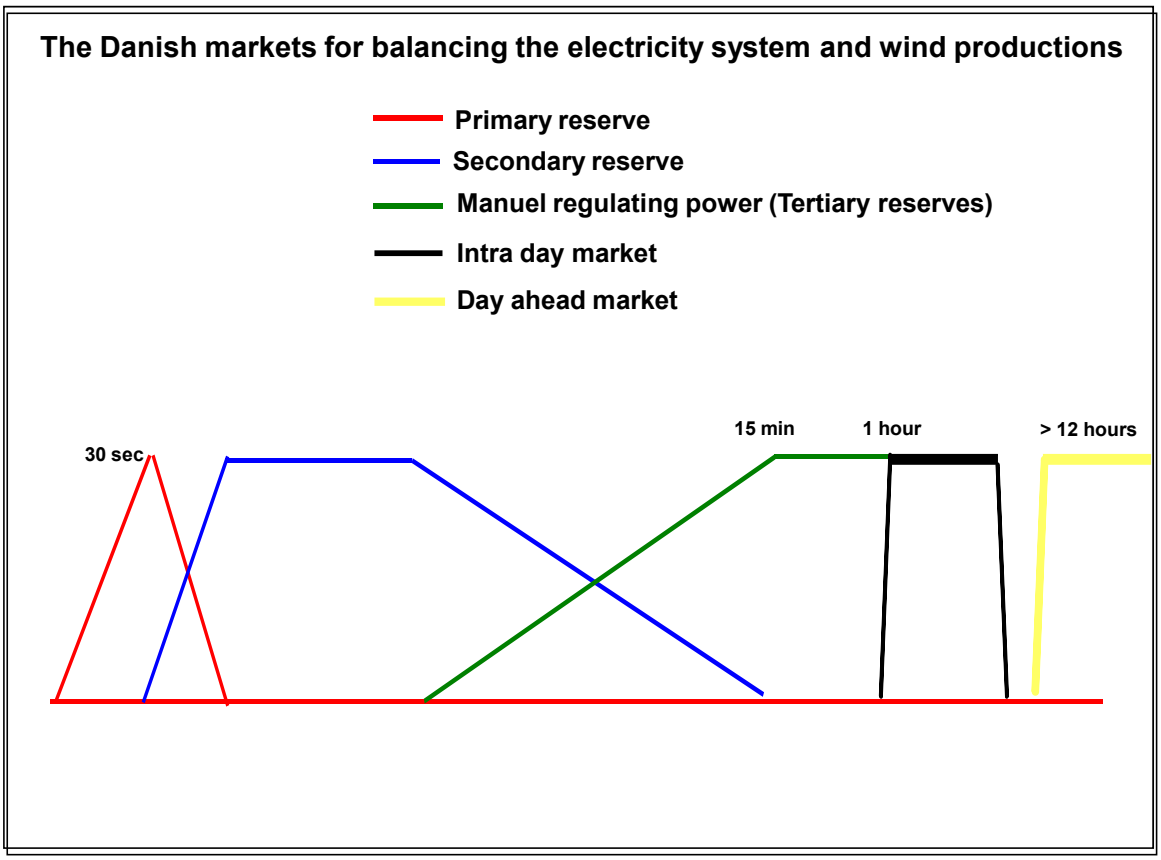

Figure 1: The tasks of delivering Active power are in Denmark split into 5 markets.

The SO has to pay the providers of reserves and to allocate costs after physical delivery to those market actors causing the system imbalance within the imbalance clearing.

Besides the regulating power the SO and grid operators also need other ancillary services like voltage control, emergency start-up, etc to securely operate the system and the re-establish system operation after a failure.

2 Success stories involving innovative marketing options

During the MASSIG-project it has become obvious that the TSO in Denmark has organized the electricity markets in a way that to a much higher extend allows the participation of small scale power producers in the electricity markets, compared to their participation in Germany, Poland and UK.

Already today small scale Danish CHP-plants participate in Primary reserve, Tertiary reserve and Day ahead spot market. The participation in Primary reserve and

Tertiary reserve (in Denmark called Regulating power market) is described in section 2.1.
Similar examples for Germany, Poland and UK are described in the subsequent sections.

2.1 Full CHP market integration in Denmark

Figure 2: Danish CHP-plants are made flexible through big thermal stores and high CHP-capacity. Typically with a heat capacity of the CHP-units around the average demand of heat in winter. In this picture is shown a 2 MW-el CHP-plant.

Figure 3: The big thermal stores at the Danish CHP-plants are equal to around 200 m^3 per MW-heat on the CHP-units.

Figure 4: Some of the CHP-plants have cooling towers, making these plants more available in the balancing markets.

2.1.1 Participation in the Primary reserve market

Won Primary reserve in West Denmark has to be delivered at a frequency deviation up to +/-200 mHz from the reference at 50 Hz with a Dead band of +/-20 mHz, and it has to be delivered linear between 20 and 200 mHz within 30 seconds.

The won Primary reserve must be maintained until Secondary reserves and the Regulating power takes over, not exceeding 15 minutes.

The Primary reserve market is organized as a day ahead Marginal price market.

This daily market is split into two markets. One market for Positive Primary reserve and one market for Negative Primary reserve. The market is further split into 6 four hour periods.

Gate closure for bidding is at 15.00 the day before.

Least offer is 1 MW, but can be made up of more units.

As an example of the possibilities for participating in the Primary reserve market Figure 5 shows the spot market operation of a typical Danish CHP-plant with a big thermal store. The figure is taken as a screenshot out of the modeling software energyPRO. The upper graph shows electricity prices at the Scandinavian spot market (elspot) of a week in June 2010, where green areas represent spot prices leading to a positive contribution margin, and red areas leading to a negative contribution margin of the CHP installation.

The other graphs show schedules of heat and electricity generation, and state of charge of the thermal store. It is shown that in times of high spot prices the CHP enter into operation, where in times of low spot prices the CHP are switched off, and the thermal boiler covers the heat demand.

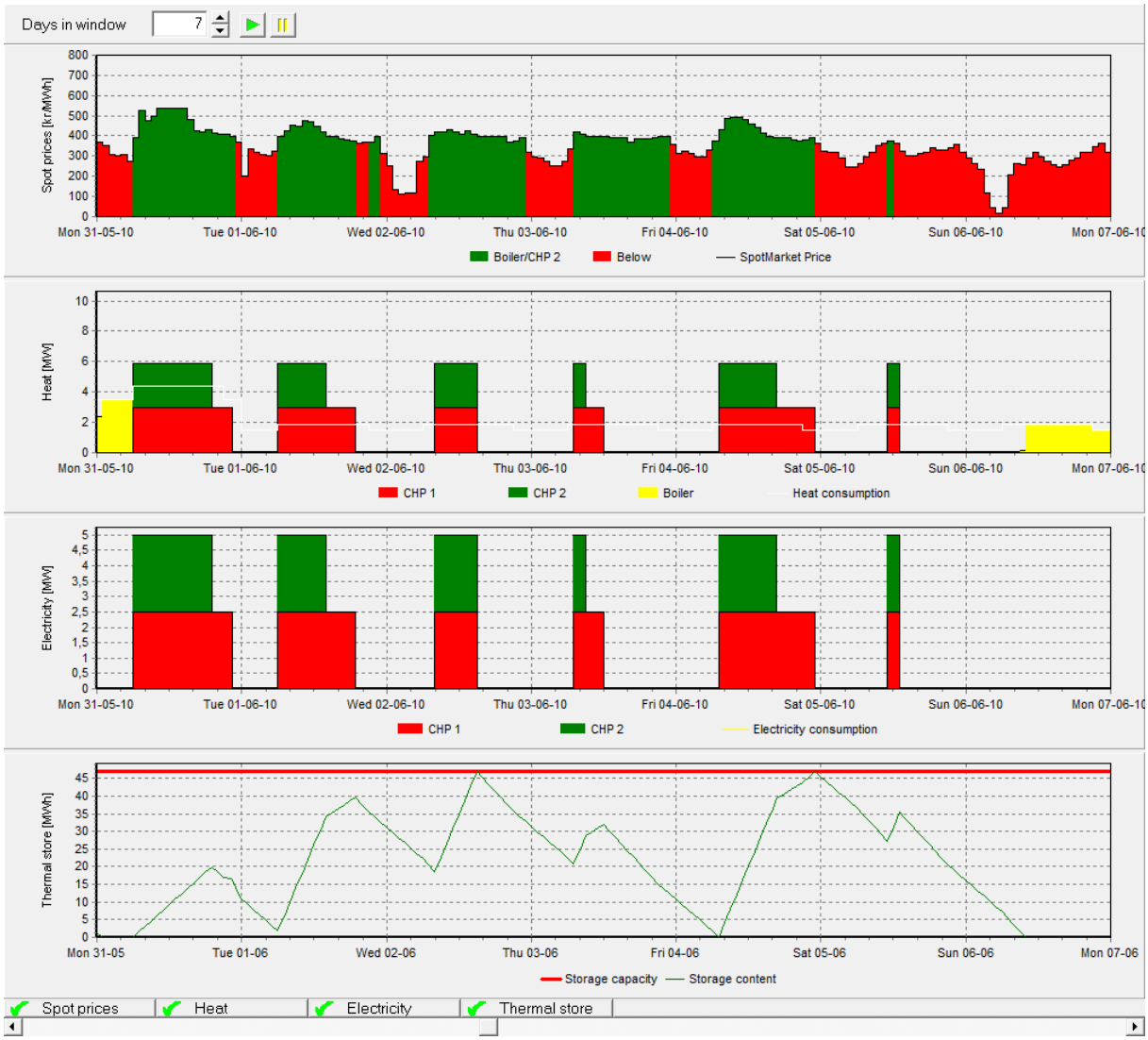

Figure 5: In this figure is in energyPRO simulated the spot market operation of a typical Danish CHP-plant with a big thermal store.

Only when the CHP-units are running they are able to regulate in 30 sec. But it is possible to plan the operation in the spot market, so that it is running in some of the 4-hour blocks offering Negative Primary reserve. If not all of the capacity is traded into spot, also offering Positive Primary reserve is possible.

2.1.2 Participation in the Regulating Power market

In the hours in which the CHP-unit is not used in the spot market it may be offered to be available for upward regulation in the Regulating Power Market. Depending on the chosen bidding prices for being available for upward regulation it will in some hours win bids, thus earn money by just being available.
In these hours the CHP-unit will also earn money if being activated.
In the hours in which the CHP-unit is used in the spot market, it may be offered to be downward regulated. Please remember that in these hours you have already received the money from the spot market, so being downward regulated will probably save you some money for buying fuel etc. Therefore you are able to offer Energinet.dk money for being downward regulated (positive bid price).

There are only three requirements for participating in the Regulating Power Market:

- The CHP-unit shall be able to start in 15 minutes.
- The CHP-unit shall be directly connected through the internet with the central computer at your energy trader, allowing this computer to start and stop the CHP-unit.
- The least offer in the Regulating Power Market is 10 MW, so it needs to be aggregated with other Small Size CHP-plants.

In Figure 6 and Figure 7 is shown the simulation of a Danish 1 MW CHP-plant during a 7 days operation period: 30-04-2009 to 06-05-2009. Again it shows that the CHP enter in operation at peak spot prices.

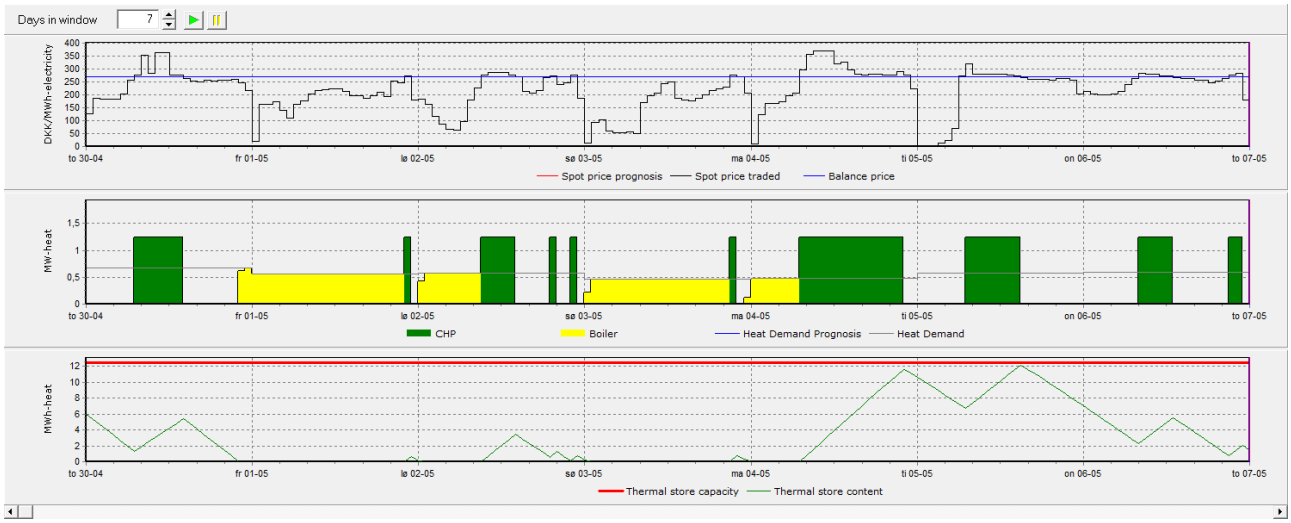

Figure 6: A Small Size 1 MW CHP-plant participating only in the spot market in the period: 30-04-2009 to 06-05-2009.

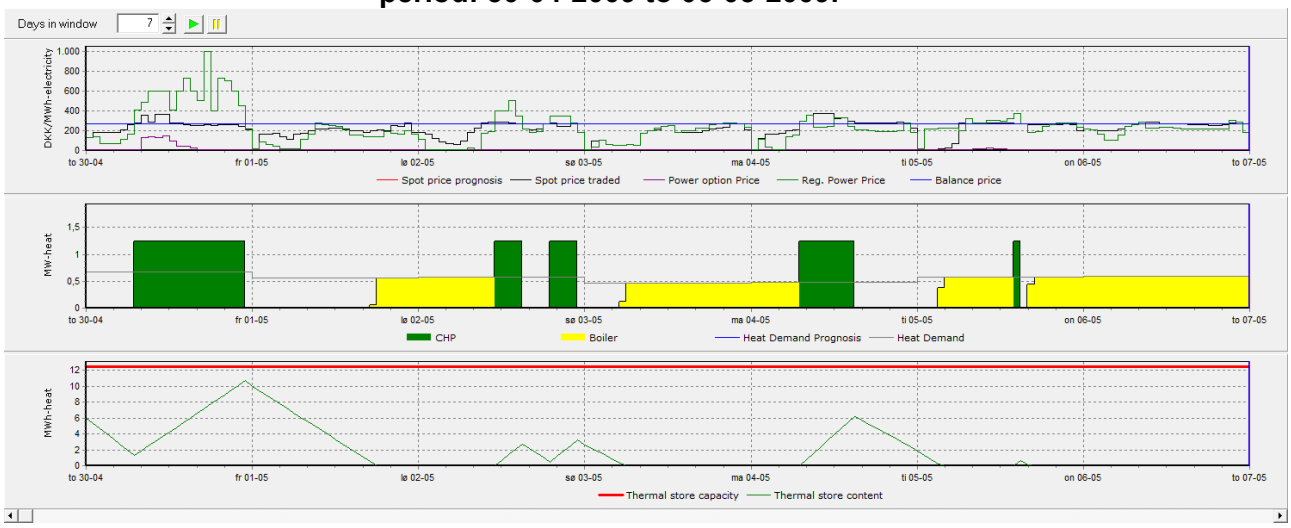

Figure 7: A Small Size 1 MW CHP-plant participating in both the Spot Market and the Regulating Power Market in the period: 30-04-2009 to 06-05-2009.

The simulations in Figure 6 and Figure 7 show that the operation of the plant depends a lot on if it only participates in the spot market or it participates in both the Spot Market and the Regulating Power Market. In Figure 7 the CHP only operate at high Spot and Regulating Power Prices.

Figure 8 shows that the CHP-plant can reduce its Net heat production costs by 21% in this chosen week, if it participates in both the Spot Market and the Regulating Power Market.

Simulation of a 7 days operation period: 30-04-2009 to 06-05-2009		
All amounts in DKK	Only Spot	Spot + Regul. power
Sale at spot market	13.344	4.861
Availability payment		1.955
Payment for upward activation		12.352
Payment for downward activation		-1.370
Net heat production costs	42.147	33.498
Profit of participating in both markets		8.649
Reduction of Net heat production costs		21%

Figure 8: Comparing the two simulations.

2.2 Participation of Badenova CHP in Spot- and Minutenreserve market

2.2.1 Description of the CHP-Plant in Freiburg-Weingarten

The German utility badenovaWÄRME*PLUS* operates in Freiburg the CHP-Plant Freiburg Weingarten. It consists of 2 gas engines with a total of 5.8 MWel (thermal power 6.3 MWth), and 3 additional gas boilers with a total of 28 MWth for covering thermal peak loads, and a thermal storage of 360 m³. The installation is connected to a 40 km district heating grid. The yearly amount of heat delivered from the plant to the district heating grid amounts to 69.000 MWth.

CHP-Plant Weingarten

Small CHP electricity is paid according to the German CHP Act. The payment consists of the average spot price for baseload electricity of the past quarter (41,02 €/MWh for the second quarter 2010), the avoided grid utilisation (about 5 €/MWh) and a fixed bonus (5,6 €/MWh in 2009). Since 2010, after 10 years of operation, the CHP in Freiburg Weingarten isn't considered by the German CHP act

anymore. This means the grid operator does not need to buy the produced electricity anymore, and the plant operator is forced to sell the electricity on a market.

2.2.2 Current process of power trading in 2010

badenova WÄRME*PLUS* negotiated with different traders and signed for the first quarter 2010 a contract with badenova AG & Co. KG and for the second quarter a contract with the German utility MVV Energie. The price for the electricity paid by MVV covers the electricity generation costs at any time, making operation of both engines possible during both peak and off-peak hours.

The utility MVV Energie offers one high tariff price (HT) and one low tariff price (NT). In the winter months, fourth and first quarter, high tariff is from Monday to Friday from 6am to 21pm and in the summer months, second and third quarter, high tariff is from 7am to 5pm.
badenova WÄRME*PLUS* tries to operate the engines as much as possible in the high tariff period by using the thermal store. But also in the low tariff period the engines are running for several hours to cover the heat demand. The operation strategy now is a mixture of heat demand driven and electricity demand driven.
If the CHP-unit in Freiburg Weingarten would still belong to the German CHP act, the payment would be approximately 50 €/MWh. In the bilateral contracts with both traders badenova AG & Co. KG and MVV Energie badenova WÄRME*PLUS* achieved payments less then 50 €/MWh, which makes the operation of the engines economically less attractive. Therefore badenova WÄRME*PLUS* needs to look for alternatives to only sell their electricity within their bilateral contracts.

2.2.3 Participation in the Spot Market and the Minutenreserve Market

First of all you have to make a contract with an energy trader (e. g. badenova, MVV Energie, Evonik, Trianel or Nordjysk Elhandel (www.neas.dk)) for taking care of selling your electricity into the Spot Market and the Minutenreserve Market.

The earnings in the Minutenreserve market (Tertiary control) in Germany are split into two components.

1. During the hours in which your CHP unit is not used in the spot market you will be able to offer it to be available for upward regulation in the Regulating Power Market (positive Minutenreserve). Depending on the chosen bidding prices for being available for upward regulation you will win your bids in some hours, thus earning money by just being available (Leistungspreis).
2. In these hours the CHP unit will also earn money if being activated (Arbeitspreis).

In the hours in which your CHP unit is used in the spot market, you will be able to offer the CHP unit to be downward regulated (negative Minutenreserve). Please remember that in these hours you have already received the money from the spot

market, so being downward regulated will at least save you some money for buying fuel, operation costs, etc.

The Spot Market is organized as a marginal price market, that is to say that the most expensive price accepted will determine the price for all accepted bids. The Regulating Power Market (both availability and upward and downward regulation) is organised as a pay-as-bid market, where bids are accepted following a merit order (Gebotspreisverfahren).

Technical requirements for the CHP unit:
The requirements for trading into the EPEX Spot market are easily to be met, as the least offer is 0,1 MWh, with hourly increments of 0,1 MWh. Connection fees, licenses and other fix/variable costs may be covered by the energy trader, who will require corresponding fees for his services.

There are a few requirements for participating in the Minutenreserve Market:

- The CHP unit shall be able to start in 15 minutes.
- The CHP unit shall be directly connected through the internet with the central computer at the energy trader, allowing this computer to start and stop the CHP unit.
- The least offer in the Regulating Power Market is 15 MW, so you need to be aggregated with other Small Size CHP plants, which is a job done by the energy trader.

Economic results and operating strategies after entering the big energy markets:

To show an example of the value of participating in the EPEX Spot market we have simulated the operation of the CHP units in Freiburg Weingarten *(*in *energyPRO)* in the first five months of 2010.

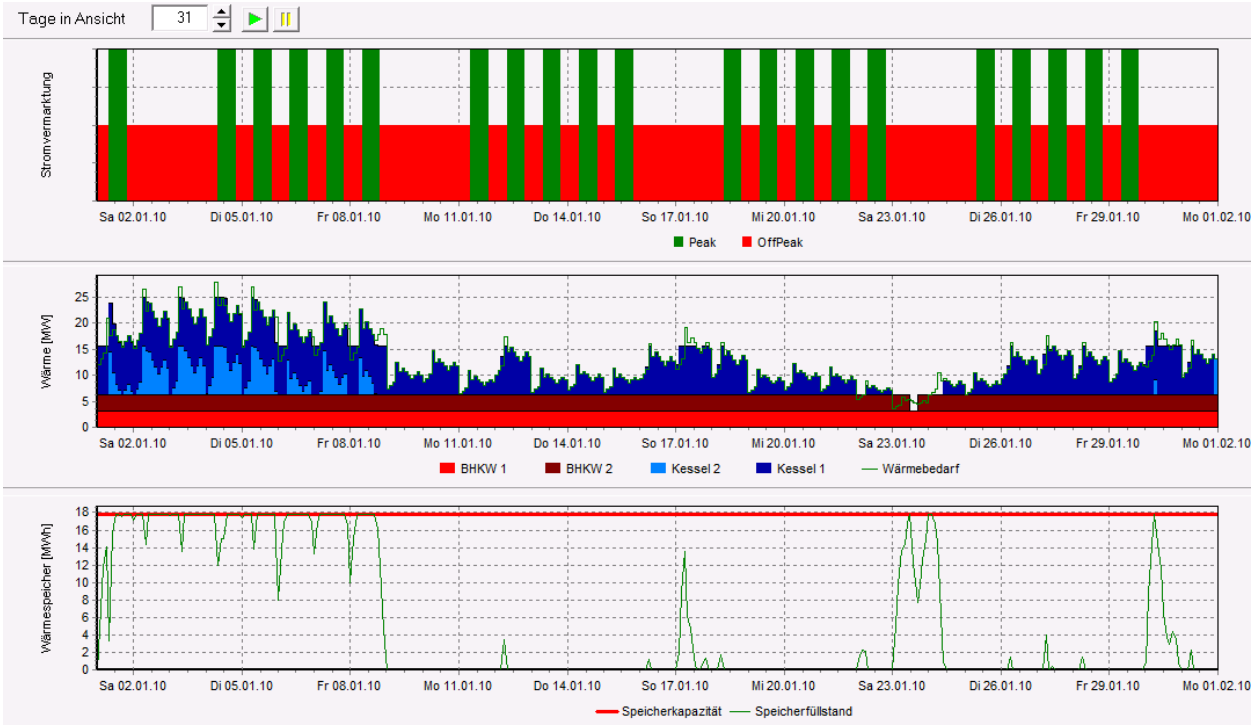

Figure 9: A graphical view of the simulated operation of the CHP units in Freiburg Weingarten January 2010 on a Peak Offpeak contract.

Figure 9 shows that in January the CHP are almost running through (brown and red curve in the middle graph), even if Offpeak electricity prices (upper graph) are not very attractive.

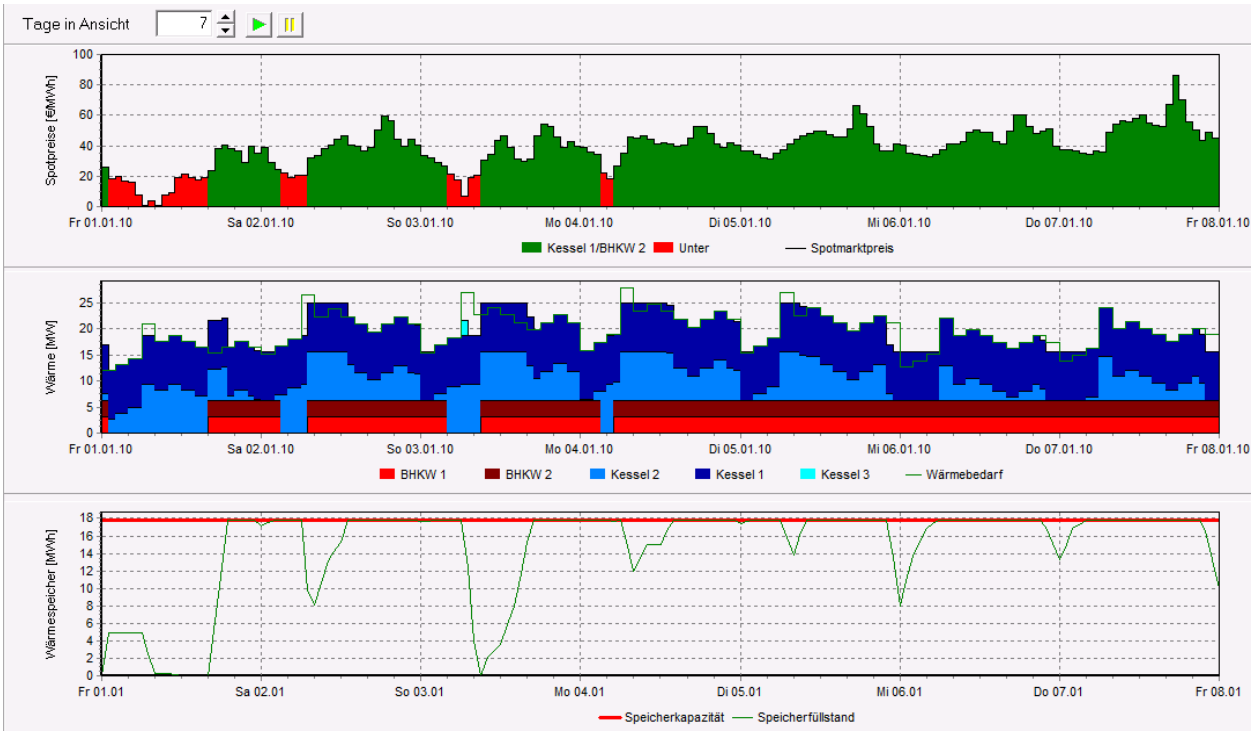

Figure 10: A graphical view of the simulated operation in the Spot market of the CHP units in Freiburg Weingarten January 2010.

Figure 10 shows that the CHP only produces when spot prices (upper graph, in green) are above the marginal electricity generation costs. The CHP operation time is reduced, being replaced by the gas boilers.

The simulations show that in the first five month the value of participating in the Spot market compared to selling on a Peak Offpeak contract is 112 thousand €.

Combined trading into Spot and Regulating Minutenreserve Market will make further improvements to the economics of the Weingarten CHP installation. Offering positive Minutenreserve in these 5 month gives very little (713 €), but offering negative gives 81 thousand € extra in these 5 month.

After losing the fixed feed in tariffs from the German CHP act it is necessary to search for new ways of power trading. The first step could be a bilateral contract, which is easy and keeps the CHP unit running. But if CHP operators enter the big markets, Spot Market and Minutenreserve Market, they can increase the operating results.

2.3 Spot market sale from biogas CHP at a Polish sewage water plant

The Wastewater Treatment Plant in Łódź (Grupowa Oczyszczalnia Ścieków - GOS) collects 170-190 thousand m^3 of sewage per day from urban and suburban areas inhabited by more than 850 thousand people. The sewage treatment process produces more than 20 thousand m^3 of biogas per day. Three Deutz diesel engines have been installed and work as CHP units with the total installed electrical and thermal capacity of 2.799 MW and 3.495 MW respectively. At their full thermal and electrical load the engines burn 1143 m^3/h of biogas or natural gas.

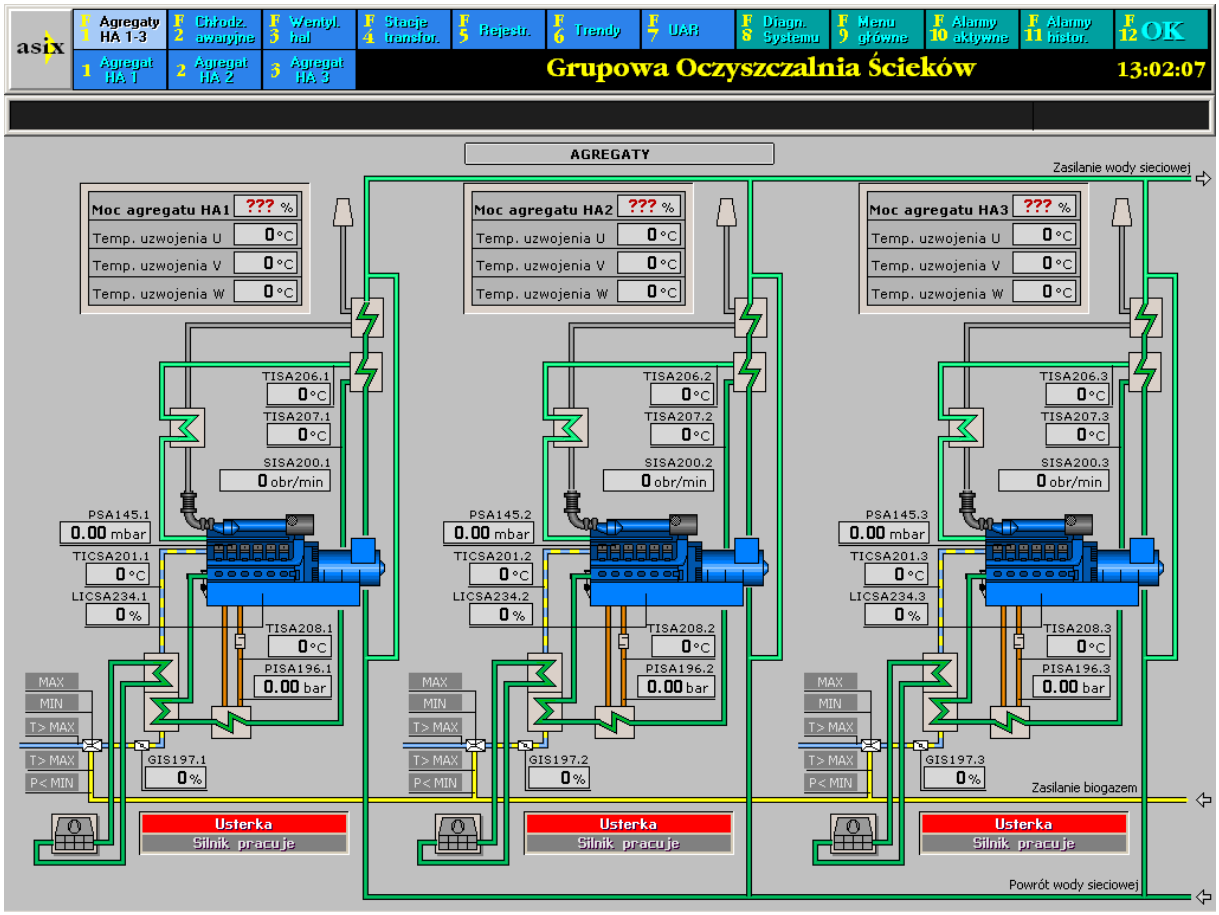

Figure 11: The layout of the three diesel engines at the GOS.

Generated heat and electricity are consumed on site in the process of water treatment. In 2008 the annual electricity consumption reached 21534 MWh and the local generation 16784 MWh. Although the company is a net electricity consumer, electricity generation is occasionally higher than consumption and excess power is exported to the distribution network (15kV). In 2008 energy exported to the grid amounted to 1005 MWh. Due to the remote location the plant is not connected to the neighbouring district heating network and excess heat can't be exported and it is dissipated in radiators. Today the plant is characterised with regular operation cycles concerning production and consumption of electricity where daily biogas production

and electricity consumption profiles are time-shifted. Currently a single biogas tank of 2500 m^3 (approximately 2h of full load running) helps to keep the forecast error near zero, but does not allow for strategic bidding.

Figure 12: Biogas storage facility at the Wastewater Treatment Plant in Łódź.

An interesting opportunity for the Wastewater Treatment Plant in Łódź to be considered is to use the biogas store for increasing the electricity production in peak hours and sell their surplus production at better prices in the spot market.
The plant has planned to increase the generating capacity and storage facilities to improve availability and flexibility of plant dispatch.

2.3.1 Electricity market access

With the current regulation of the Polish electricity market independent participation in the wholesale market is limited to generators connected to the EHV transmission network (400 kV and 220 kV) and HV distribution networks of 110 kV.
Large generating units connected to those networks can directly or indirectly[1] participate in the wholesale market and they are automatically involved in the passive or active operation of the Balancing Market (BM) run by the TSO (PSE-Operator S.A.).

[1] Indirect participation in the electricity market means that the plant or unit is represented by the third party, who on behalf of the unit trades the electricity in the wholesale market and submits generation schedules to the TSO/DSO.

For smaller size RES and CHP units connected to local MV and LV networks participation in the wholesale market is possible only through third parties called Balancing Responsibility Party (BRP) that have to be member of the wholesale Balancing Market. For generators and consumers staying out of the market, the local DSO plays the role of a BRP and takes care of balancing of this part of the local distribution network.
The total imbalance cost incurred by the BRP in each settlement period (1 hour) and calculated by the TSO is transferred to consumers and producers supervised by the BRP. Customers are settled either according to individual deviations according to readings of their metering systems In case the appropriate metering system is not available, standard consumption profiles are used for the calculation of the imbalance cost. Power producers are settled according to readings of their metering systems (generating units participating in the market have to be equipped with bi-directional, four-quadrant metering systems of at least 1 hour resolution and the daily data transmission function).

Day ahead to the delivery day BRPs have to submit to the DSO their schedules (or daily production profiles) defined for each node of the wholesale market network area (400, 220 and 110 kV substation busbars). After the delivery is completed BRPs are settled against any deviations from the submitted schedules. In contrast to the Transmission Network Grid Code describing in details the imbalance settlement rules, the Distribution Grid Codes do not define explicit rules for the settlement of imbalances. The balancing procedure and the rules to settle imbalances are part of the agreement between the BRP and the producer. The typical solution is that imbalances are calculated individually at each grid connection point and the System Sell Price (SSP) and System Buy Price published by the TSO in the Balancing Market are then used by the BRP for the calculations of individual costs of deviations from the forecasted hourly production schedules.

In that way RES and DG may use the following market options:

1. Large and medium size plants (large wind farms, large CHP units), usually connected to 110 kV distribution network, can trade their output at the wholesale market in bilateral contracts (OTC market), via power exchange (the minimum bid size at the Polish power exchange is 1 MWh) or via other electronic trading platforms. Large RES and DG plants entering the wholesale market have to act as BRP and sign transmission agreement with the TSO (PSE-Operator S.A.). In this way they become automatically passive or active participants of the Balancing Market. They may also select a third party to be their BRP and represent the participant at the Balancing Market. The imbalances are calculated individually at Grid Connection Points (clustering of generating units connected to 110, 220 and 400 kV grids is not possible).
2. Because the wholesale electricity market in Poland covers only HV network area (physical nodes), smaller units connected to MV and LV grids can participate in the wholesale market using **virtual network nodes**. In this case the owner of the plant needs to become a BRP himself or find a third party BRP who will take care of balancing and settlement of the unit at the Balancing Market. Smaller generation units are then allocated by the TSO to

the BRP's virtual network node. Since the ICT systems required for the participation in the Balancing Market are expensive (as explained in the work package WP3), only the second option (using third party services) is economically feasible for small producers and they need to find a trader or larger producer, who will play the BRP role for their plants and will submit individual or aggregated production schedules and settle imbalances with the TSO. For units connected to the virtual network nodes aggregation of production schedules is possible and the BRP is settled against aggregated imbalances of all units allocated to the same virtual network node, even if they are physically located in distant network areas. How the total cost for the aggregated imbalances is distributed among BRP's generating units is defined in the agreement between the owner of the plant and the BRP. In practice some smaller producers are ready to face the full risk and decide to be settled individually for their imbalances. In this situation they get normal wholesale market price for electricity exported to the grid. Other smaller producers prefer to eliminate the imbalance risk and accept market prices reduced by a risk premium charged by the trader (BRP).

3. Smaller RES and CHP, which are risk averse have an option of selling their output to a "supplier of last resort" (usually the local distribution company) for the must take price. Within this option the owner of the plant doesn't need to choose the BRP (the local DSO automatically become its BRP), doesn't need to submit production schedules and is free of the imbalance risk. The must take price offered by the last resort supplier is set by the Regulator and calculated as an average of competitive market prices of the previous year.

The three options mentioned above are independent from "green" and "red" certificate trading, conducted by RES and CHP in parallel to the energy trading.

Bearing in mind the currently available trading options, the daily biogas production pattern, the installed generating capacity and the available gas storage facility, the Waste Water Treatment Plant in Łódź has initially decided to stay out of the competitive market and sell the surplus of generated electricity to the local DSO, PGE Dystrybucja, Oddział Łódź.

2.3.2 Gain and loss evaluation and the MASSIG project

For the purposes of the MASSIG project alternative marketing options have been theoretically considered for the Waste Water Treatment Plant in Łódź. The conducted economic analysis of available market options using power exchange price index as the reference price showed that trading energy through the power exchange would bring much more profits than selling plant's output to the last resort supplier, see table below.

	Plant	Gen1	Gen2	Gen3
Feed-In Tariff/Contract Traded Volume [MWh]	2002.9	667.8	671.4	663.7
Feed-In Tariff/Contract Income [PLZ]	*257969.3*	*86009.5*	*86477.9*	*85481.9*
Day Ahead PX Traded Volume [MWh]	2002.9	667.8	671.4	663.7
Day Ahead PX Rejected Volume [MWh]	0	0	0	0
Day Ahead PX Income from Energy Trade [PLZ]	388854.5	128987.8	129697.7	130168.9
Day Ahead PX Variable Cost [PLZ]	-1341.9	-447.4	-449.8	-444.7
Day Ahead PX Annual Fixed Cost [PLZ]	-1890.0			
Day Ahead PX Financial Balance [PLZ]	*385 622.6*	*128540.4*	*129247.9*	*129724.3*
Imbalance Profits/Losses [PLZ]	0	0	0	0
Final Result [PLZ]	*127653.3*	*42531.0*	*42770.0*	*44242.4*

The table shows that switching to trading into the power exchange might double the income of the plant and this option is now considered by the management board of the company. However before the final decision will be taken additional questions should be considered and analysed. First of all the economic analysis ought to be extended into longer period of time as the last two years were the period of turmoil with significant price volatility in the Polish electricity market.

2.3.3 The implementation of market options

Since the biogas production daily profile and the consumption of electricity are shifted in time, the installation of additional units and the increase of the capacity of storage facilities will result in additional flexibility concerning various market options, as well as further increase of plant availability and reduction of forecast errors. Bigger volumes of energy submitted to the market will allow exercising options which are not available today (e.g. trading through the power exchange). The increased predictability and stable daily production profiles should make the participation in the retail market feasible, for example by trading plant's output directly to local end-customers (e.g. SME). To make independent traders interested in the retail market and the co-operation with smaller size generating units, clear market rules and better access to customers provided by totally independent DSO (unbundled) are required.

The electricity trade in Poland is conducted predominantly in the wholesale market, mainly within bilateral contracts, and in the past the power exchange covered only small share of the total demand (<3.5%). The number of independent traders is tiny and their traded volume covers only small part of the total electricity consumption (approximately 15%). There are a little more than 100 active customers exercising their TPA (Third Part Access) rights and the switching rate is extremely low (between 2007, when all 15 mln Polish electricity consumers became eligible customers, and 2009 only 956 customers changed their suppliers). The development of the dispersed generation has just taken off and the lion's share of CHP and RES income is earned from selling "green" and "red" certificates. Last but not least, the current

electricity market structure and rules, with no intraday market and ancillary services provision reserved only for large power plants, don't encourage small producers thinking of entering the competitive market.
These facts and figures show that beyond economic aspects, there are important barriers linked with the poor progress in liberalization of the electricity market in Poland, the flawed regulation and customers' passiveness and conservatism resulting in inefficient operation of the retail market, which should invite an active participation of smaller customers, including small RES and DG.

There is a need for urgent and fundamental changes in the architecture and operation of the Polish electricity market. The Regulator (Urząd Regulacji Energetyki URE) and the TSO (PSE-Operator S.A.) keep making and announcing plans of revolutionary changes in the market design, but since 1999, when the electricity market in Poland went live, only small adjustments have been made to the original blueprint.

2.4 Participation in Short Term Operating Reserve provision in UK

In UK it is possible for small scale power producers to participate in the Short Term Operating Reserve market. This present option is described by going through the offer to small scale power producers made by the company Flexitricity Limited (http://www.flexitricity.com).

Flexitricity Limited has been established in 2004 in Scotland as a Virtual Power Station (VPS) uniting a number of small power producers (business partners) and electricity loads located on industrial and commercial sites and spread over the UK territory – Edinburgh, Nottingham, Birmingham, Yorkshire, Kent, etc.
Flexitricity's real-time aggregation system and process-led approach gives small generators the opportunity to exploit their flexibility and to access premium energy prices by reducing electricity consumption, or running generators within the short periods when the national electricity system is under stress.
Flexitricity communicates directly with standby generators and/or electricity consuming equipment on the partners sites via secure internet connections, aggregating them into a 'virtual power station'. All assets connected to Flexitricity are continuously monitored, and can be informed immediately of any concerns.

Flexitricity sells services such as Short Term Operating Reserve (STOR) to National Grid to help with this process, and provides revenue from STOR to the industrial and commercial electricity users and generators who participate.
There are three options for running generators with Flexitricity:
1. Full parallel running – generators start, synchronise with the mains, and ramp up to a fixed output power. The mains remains connected while the generators are running.
2. Short term parallel (STP) running – this mode is also known as "soft load transfer" or "bumpless transfer". Generators start and synchronise with the mains, then ramp

up power until the generator output equals the site load. The mains circuit breaker is then opened, and the site runs as an “island”. Stopping generators is the reverse process.
3. Changeover or “break transfer” – site load is transferred to generator power with a break in the mains supply. This mode is only suitable for Flexitricity operation if the full site load is supported by a high integrity Uninterruptible Power Supply system.

2.4.1 Short Term Operating Reserve (STOR)

STOR is a contracted Balancing Service providing an additional active power generation amount and/or power demand reduction to keep the electricity system stable.
STOR is one of National Grid’s key reserve purchases. Fast-acting generators are held in readiness so that National Grid’s control centre can start them quickly if a large power station fails, or if demand is higher than forecast.

STOR provider must satisfy the following technical requirements:

- To aggregate a minimum of 3MW or more of generation or steady demand reduction (this can be from more than one site).
- To deliver full MW within 240 minutes or less receiving instructions from National Grid.
- To provide full MW for at least 2 hours when instructed
- To have a Recovery Period after provision of Reserve of not more than 1200 minutes (20 hours)
- To be able to provide STOR at least 3 times a week

Flexitricity is called only for STOR provision when the national electricity system is under stress.

Presently Flexitricity participates in the STOR Flexible Service (FS).

FS allows providers to make themselves available for particular Windows – time periods of each day when FS is required, which are set up by National Grid for some future period (for example, for the period of 1st of April 2010 – 31st of March 2011).

Where at 10:00 hours on each Friday Flexible Service availability is being declared in respect of Availability Window(s) in the following week, National Grid will assess whether to accept or reject the declared Flexible Service availability.

Where availability in any Availability Window(s) is not rejected by National Grid, the service provider is then committed to provide the service in such windows.

Flexitricity provides STOR FS by starting standby generators, reducing consumption, and turning up CHP and hydro generators, on instruction from National Grid.
Due to Flexitricity is fully automated on most sites, site operators do not need to have any routine involvement in Flexitricity operation but at the same time it is possible to

route Flexitricity calls through the control desk, giving to operators direct involvement in the process: they can opt out of STOR FS at any time using a switch.
Contact with all partners for obtaining necessary information about their power production output is carrying out every ten seconds electronically- by connection of Flexitricity communication equipment to the partners' controls. For that purpose Flexitricity uses an electronic system of its own invention.
All listed below equipment is grouping (and periodically re-grouping) based on the STOR FS technical requirements, response time and how often each of the partners (will) ready (intend) to respond to National Grid call.
(This information is included in the contract between Flexitricity and each of partners.)
After getting a National Grid call power generation starts or reduces/stops automatically by using certain power generation group(s) on the base of information obtained concerning availability and readiness of each individual group for service provision and depending on the each call specific requirements.
For the STOR FS provision Flexitricity is running by the following types of electricity equipment:

- Standby diesels in a range of 500 kW - 3 MW serving as an emergency generators with response time in a range 0.5 - 5 min
- Steam turbines with a total of about 10 MW and with response time period 0.5 - 5 min
- Gas engines in a range of 500 kW - 3 MW and with response time period 5-10 min
- Pumping and hydro in a range of 200 kW providing instant response or response within the few minutes time period
- DRUPS (Diesel Rotary Uninterruptible Power Supply) in a range of 500 kW - 3 MW providing an instant response because many standby generators are capable for faster operation.
- Load: refrigeration systems- cold storage, in a range of 10 kW -100 MW with an instant response. (Load sharing, load acceptance and site load profile must all be properly balanced and considered alongside G59/G75 protection requirements.)

2.4.2 Benefits and economic profitability

A number of benefits obtaining by Energy partners aggregated in the VPS are given below:

- New revenue earned by existing assets;
- The majority of the revenue comes from availability payments, paid regardless of the amount of running, and therefore predictable;
- STOR FS running is typically similar to a good-practice generator test and exercise regime, and substitutes many elements of it;
- The reliability of the site's emergency power supply is dramatically enhanced;
- Remote monitoring of standby generator health.

The payments for STOR FS are shared with the Energy Partners, owning the assets Flexitricity uses in accordance with the terms of the contract between Flexitricity and Energy Partner.
Contract terms provide a strict percentage value which Energy Partner obtains from the sum paid by National Grid to Flexitricity.

3 Conclusion

Especially in energy systems with large amounts of fluctuating renewable energy productions it is important that all intelligent electricity generation participates in the integration of these fluctuating productions. Distributed small scale power producers are becoming a bigger part of the electricity supply; therefore it becomes more and more important that they also deliver intelligent generation through e.g. the Spot market and the balancing markets.

During the MASSIG-project it has become obvious that the TSO in Denmark has organized the electricity markets in a way that to a much higher extend allows the participation of small scale power producers in the electricity markets, compared to their participation in Germany, Poland and UK.
Without intraday trading (considerable imbalance cost), trading volume barriers, no access to ancillary services trading and high entrance costs the Polish electricity market turned out to be the less advanced and less DG friendly market.

It has shown up that it is important that each market is organized in a way that makes it easy and affordable for small size generators to participate in the market. It seems clear that a market organized as a marginal price market (single price market) is easier for small size generators to participate in compared to a market organized as a Pay As Bid-market. In a marginal price market, where every accepted offer gets the same price, each small size generator can focus on calculating its own costs of participating when making its offer in the market.

BUT in this Delivery 6.3 have been described some present market options for small scale intelligent generators in Denmark, Germany, Poland and UK, that already today are available for small scale power producers.