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FENIX deliverable D3.3 Report:

FINANCIAL AND SOCIO-ECONOMIC IMPACTS OF EMBRACING THE FENIX CONCEPT

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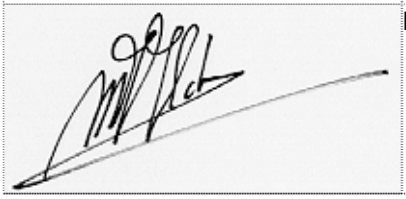	Martin Scheepers	ECN	30 September 2009

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Abstract

This document, which was issued in the framework of the EU-sponsored FENIX project, brings out the key results of cost-benefit analyses of FENIX applications in the FENIX Southern and Northern Demonstration projects. The net benefits of FENIX flexibility applications under present-day and future baseline circumstances with a year 2020 time horizon are compared with FENIX operational practices at the system level as defined and delineated by the Southern and Northern Demonstrations. The report focuses on selected promising applications for flexible distributed generators. Results of cost-benefit analysis are considered from the perspectives of key stakeholders and society. The report demonstrates that the FENIX flexibility concept has great potential to create additional value to distributed energy resources and their business partners, network system operators and society at large in a variety of applications.

CONTENTS

Glossary of acronyms and abbreviations

BM	Balancing Mechanism: a market-based arrangement that penalises BM Units for measured physical deviations from off takes and injections as specified by their final notifications to NGC
BM Unit	Market party that has to comply with - and is liable to settlement by - the BM
DEFRA	Department for Environment, Food and Rural Affairs
CCL	Climate Change Levy: a levy to be paid by non-domestic end users in the UK ad £4.30 per MWh as per 1 April 2001 annually revised based on the consumer price index
CHP	Combined Heat and Power
CVPP	Commercial Virtual Power Plant; commercial aggregator of DER, e.g. DG, based on ICT-based operational control of these resources
DER	Distributed energy resources
DG	Distributed generator (generators), a generator (generators, each) feeding into a low/medium voltage distribution grid
EEE	Equivalent Electric Efficiency. CHP plants in Spain have to fulfil some minimum efficiency requirements in order to be eligible for bonuses. Such minimum requirements are defined through the EEE
FPN	Final physical notification
GB	Great Britain, the UK excluding Northern Ireland
IPN	Initial physical notification
LEC	Levy Exemption Certificates: market support mechanism for power generated by High Efficiency CHP plants and for eligible renewable electricity
NGC	National Grid Corporation, the TSO of the GB transmission system
NS	Northern Scenario
OFGEM	Office of Gas and Electricity Markets
RES	Renewable Energy Sources
RO	Renewable Obligation: main market support mechanism for eligible renewable electricity in the UK; as per 1 April 2009 three technology bands have been introduced with distinct generation requirements per one ROC to be issued
ROC	Renewables Obligation Certificate
SBP	System Buy Price, the price a BM Unit has to pay NGC per MWh when he is short in a certain settlement period (power fed in less or power taken off more than notified)
SS	Southern Scenario
SSP	System Buy Price, the price a BM Unit has to receive from NGC per MWh when he is long in a certain settlement period (power fed in more or power taken off less than notified)
STOR	Short Term Operating Reserves; tertiary (cold start) reserves that are contracted annually - and activated upon call - by NGC
UK	United Kingdom
UK APX	Power exchange in the UK

Executive Summary

This report presents key results of cost-benefit analysis simulations for applications of FENIX concepts to *flexible distributed generation*. Key to the FENIX concepts is flexible operational aggregation of distributed energy resources (DER: flexible distributed generation, power storage facilities, flexible loads) by a virtual power plant (VPP). In principle, a VPP consisting of a portfolio of aggregated distributed energy resources can be remotely monitored and operationally controlled just like a conventional large-scale power plant, owing to the application of advanced information and communication technology. A commercial VPP (CVPP) can apply FENIX concepts on behalf of DER to optimise the financial result of DER participation in electricity-related markets, whilst a technical VPP (TVPP) can do this on behalf of a distributed system operator (DSO) to optimise the procurement of auxiliary system services.

This report considers quantitatively CVPP applications for flexible distributed generating plants (DG) under conditions prevailing in the UK (Northern Scenario) and Spain (Southern Scenario) today, and in the medium-term future (year 2020) for the selected FENIX applications at small-scale level and scaled up at large-scale national level. The following alternative cases were assessed against the scenario-, time- and scale-specific "without FENIX" reference case:

<u>Northern scenario</u>

- *Optimised wholesale market participation*: instead of DG operating at fixed hours during the day, their operating schedule is optimised by a CVPP to maximise net revenues from the Day Ahead wholesale (DA) market.
- *Balancing services to the Transmission System Operator:* contingent on contracted optimised DA market transactions, the CVPP concerned offers upward or downward balancing services to the TSO.
- *Intra-day adjustment services to the Supplier:* as an alternative to the preceding application the CVPP offers contingent upward or downward adjustment services to the Supplier with whom he transacts for participation in the wholesale market.
- *Tertiary reserve services to the Transmission System Operator:* for designated time windows the transmission system operator (TSO) solicits offers for tertiary services, which the CVPP considers on its commercial merits as an alternative to offering during these time windows the other DG services considered under the aforementioned bullets.

<u>Southern scenario</u>

- *Commercial aggregation*: the CVPP bundles the wholesale market transactions of DG operators without engaging in operational aggregation (i) to capitalise on the portfolio effect regarding imbalance positions reducing imbalance penalties and (ii) to reduce administrative costs.
- *Optimised wholesale market participation:* instead of flexible DG under control of a CVPP operating at fixed hours during the day, their operating schedule is optimised to maximise net revenues from the wholesale power market; because of Spanish regulation on CHP market stimulation only production adjustments in downward direction are considered when market prices are becoming too low, rendering pre-adjustment production levels commercially unattractive.
- *Active internal balancing*: contingent on contracted optimised wholesale market transactions the CVPP arranges operational adjustments to minimise aggregate imbalance positions of DG under his control.
- *Balancing services to the Transmission System Operator:* contingent on the intended operational status based on the previous applications, the CVPP offers upward or downward balancing services to the TSO.

The report provides evidence that embracing the FENIX concept is an attractive business proposition for business stakeholders with DG assets, their direct business partners –including notably the CVPP operator - and the electricity sector at large. On the other hand, large-scale

central generators will face fiercer competition and see their market power challenged by flexible DG. Our findings indicate that these impacts of applying FENIX concepts hold at present and in the future, also when this concept will be adopted economy-wide. When each application is considered in isolation, in the Northern Scenario *Optimised wholesale market participation* creates most value with *Balancing services to the Transmission System Operator* providing substantial extra value. In the Southern Scenario *Balancing services to the Transmission System Operator* is the most attractive application.

On balance, the electricity system at large will also create additional value by adoption of FENIX concepts because of system-wide gains in terms of absorbing intermittent renewables at lower costs, higher fuel efficiency and improved functioning of markets within the realm of the electricity system wherever VPP-optimised flexible DG services will be offered. It is paramount for deployment of FENIX that enabling regulatory and contractual frameworks facilitate the sharing of FENIX benefits by key direct stakeholders. Depending on national regulatory frameworks, direct stakeholders, the support of whom for introduction of FENIX is crucial, include DG operators, CVPP operators, suppliers, TVPP/DSOs, and/or TSOs.

Through enhanced competition and adjustment of regulatory framework conditions, consumers are poised to absorb their fair share of the value that embracing the FENIX concept will create within the electricity sector. On top of substantive value creation for stakeholders in the electricity sector, adoption of FENIX has also positive externalities, related to improved security of electricity supply at the backdrop of prospective high penetration of intermittent renewable power generation such as wind and solar power, reduced gas supply dependency and CO_2 emission reductions.

1. STUDY SCOPE AND APPROACH

1.1 Background and objectives

Future electricity systems are facing highly challenging conditions. These include accommodating the societal needs for low-carbon energy and consequently rapidly increasing levels of distributed and renewable generation, and mounting needs for renovation of aging networks, notably at medium and low voltage levels. Network integration of intermittent generation sources such as wind power and photovoltaic (PV) causes special problems but, at the same time, offers great opportunities for innovative new concepts. The prevalent 'fit and forget' approach to network operations that are growing in complexity and the consequential staggering network investment requirements turn out to be increasingly difficult to sustain.

The FENIX project has focused on the key issue of addressing the complexities now and in the future up to year 2020 of network integration of DER (distributed energy resources: generators, end users and providers of storage services connected to medium and low voltage electricity distribution networks) in a technically effective and economically efficient way. As for DER, within FENIX the focus is put on distributed generators. Among others, the project:

- designed a conceptual framework for remote control and operational aggregation of distributed energy resources connected to medium- and low voltage distribution networks into VPPs (virtual power plants) to improve their commercial performance and to contribute to network and system management.
- defined a great variety of practical applications of the FENIX concept, and
- carried out two technology demonstration programmes of the FENIX concept in the UK and in Spain to prove the technical feasibility of a promising selection of these practical applications.

This report, the deliverable of Task 3.3, investigates the economic feasibility of the FENIX concept for specific *prima facie* promising applications by way of cost-benefit analyses of realistic simulations. It sets out:

- *To prove, under present and future conditions facing the European electricity industry, the economic value of flexible DER operations*
- *To demonstrate that existing and new business models stand to profit from this economic value.*

In doing so it addresses the following research questions:

- *What is the value of FENIX applied at small-scale level, i.e. the level of a single part of a distribution network, for key market stakeholders and society under current market conditions?*
- *What is the value of FENIX applied at small-scale level for key market stakeholders and society under future market conditions prevailing by year 2020?*
- *Does wide-scale up-scaling of high-benefit FENIX applications at economy-wide level materially change the business case of embracing the FENIX concept?*

1.2 Scope

In order to cover a scope as broad as possible, but also considering that a dedicated CBA for each EU Member States would require much more time and effort, two different scenarios were selected: one in the UK (Northern Scenario) and another one in Spain (Southern Scenario). Each country has its own regulation and the data availability also differs from one scenario to the other. Therefore, although the aim and the methodology applied to both scenarios are the

same, the results for both scenarios and the presentations thereof are broadly comparable but include country-specific features as well.

In order to check the consistency of the conclusions drawn, for each scenario different time horizons were considered. First, an analysis for today was made, by using the real data pertaining to base year 2006 (Northern Scenario) and 2007 (Southern Scenario), in order to assess the chances for FENIX to be implemented right now. Then, the same analysis was performed for 2020. As no real data were available for 2020, a set of assumptions and projections on key parameter values were used based on outcomes of recent related studies and expert judgment. Much effort was made to obtain feedback from experts within and outside the FENIX consortium to make our scenario assumptions plausible. As a final step, the portfolio considered in each scenario was scaled up, in order to estimate the economic impact that a large-scale implementation of FENIX could have on the different market participants and society at large.

In order for the FENIX concept to be able to be implemented, many different parties in the electricity supply system need to be involved in its development. In particular, the focus is put on the investors (DER unit owners and the CVPP) and their direct business partners, grid operators and the regulatory authorities. Investors expect their business to be profitable, grid operators' target is to guarantee the supply of electricity at the lowest cost possible and regulatory authorities aim at improving the efficiency of the electricity (and heat) supply system from the societal point of view.

In identifying realistic applications of the FENIX concept, in the simulations for the cost-benefit analyses a close connection has been sought with the realities on the ground. Therefore, the ongoing Northern Demonstration of the Northern Scenario at Woking Borough (UK) and the Southern Demonstration of the Southern Scenario at Alava (Spain) have been chosen as points of departure for simulations of conditions under the Northern and Southern Scenario respectively.

In line with the whole FENIX project, for DER the focus has been put on flexible distributed generators (DG) whilst in the Northern Scenario also flexible heat storage has been considered. It goes without saying that if the FENIX concept is economically sound for these DER sources this holds a fortiori when the focus is widened to include flexible demand and flexible electricity storage as well.

An important limitation of the *quantitative* CBA analyses of FENIX applications is that they do not include impacts on network investments. It is recognised that operators of distribution networks (DSOs) are able to postpone network investments by intelligent use of DER flexibility. As DER can support network congestion management, active network management with deployment of DER flexibility enables DSOs to enhance their ability to cope with localised congestion. This enhanced capability enables better use of existing networks and, contingent on local topological conditions, deferral of network reinforcement investments. Moreover, using DER flexibility may allow DSOs to procure cheaper the provision of required reactive power services and to reduce network energy losses than in the 'without case'. These issues which are linked to the TVPP concept are analysed in a qualitative way later on in the report.

1.3 Report outline

The organisation of this report is as follows. Chapter 2 provides a brief description of the applications of FENIX-ICT endorsed operational flexibility considered in this report. These applications are described in detail in FENIX deliverable 3.1 (Aunedi *et al.*, 2008). Chapter 3 gives an overview of the key results of a large series of simulations for Cost-Benefit Analysis case studies, focusing on applications of the FENIX concept on participation of flexible distributed generation in power system related markets in the Northern and Southern Scenarios through a CVPP. A qualitative analysis of the provision of ancillary services by DG to DSOs by virtue of DSO-operated TVPPs is given in Chapter 4. The report winds up with concluding observations in Chapter 5.

2. SELECTED FENIX APPLICATIONS

2.1 Introduction

This chapter outlines different selected FENIX flexibility applications in the Northern and Southern scenario respectively (see Sections 2.2 and 2.3). The different applications are shortly summarized in Table 2.1 below.

Table 2.1 Summary of case studies in NS and SS

Case Study	Northern Scenario (Woking)	Southern Scenario (Alava)
Reference	*Fixed generation profiles*	*Fixed generation profiles*
1	Optimised *wholesale market participation*	(Non-operational) *Commercial aggregation*
2	*Balancing services* to the TSO	Optimised *wholesale market participation*
3	*Intra-day adjustment service* to the energy supplier	Active *internal balancing*
4	*Tertiary reserve service* to the TSO	*Balancing services* to the TSO

2.2 Northern Scenario

The case studies are patterned on the existing situation of a non-public distribution network in Woking Borough which connects among others about 4.3 MW_e of distributed generation, of which about 2.5 MW_e of flexible distributed generation, notably CHPs with gas engines which dispose of high ramping rates upwards as well downwards. The Woking network is operated by an aggregator. The 'Woking' network has four points of interconnection with the public distribution network of EdF Energy (EDFE), henceforth also referred to as the Supplier[1]. The Supplier measures the net energy exchanges with Woking and settles the energy bill with Woking aggregator based on these net meter readings. The following five Northern Scenario (NS) Cases are considered:

1. *Reference case:* The reference case (see Figure 2.1) is defined in such a way that the value of FENIX flexibility can be readily assessed. The energy rate the Supplier's network, charges (pays) to Woking Aggregator for positive (negative) net exchanges with the Aggregator in each half-hourly settlement period are based ex post on the wholesale price at the UK APX power exchange and include a charge by the Supplier to the Aggregator on account of the network services provided by EDFE. Woking aggregator assumes responsibility for operating the Woking network and for financial settlement with Woking network users for energy exchanges with its network. The settlement prices are derived from the ones between the Supplier and Woking and include a charge for the services of the Aggregator. Woking PV output is considered as negative demand. Each Woking CHP plant operates at fixed time windows during the day in each of the four seasons at full load, except for a scheduled overhaul period during summer and unscheduled outages. Certain separate heating facilities are in operation when the CHP plants deliver less heat than required by heat users (a swimming pool, space heating by utility buildings, stores and domestic customers). All distributed generators operate their plants themselves independently. The Aggregator does not exert operational control over the generators in his service area; he merely acts as a financial aggregator.

[1] EDFE's network business is legally unbundled from EDFE's supply business.

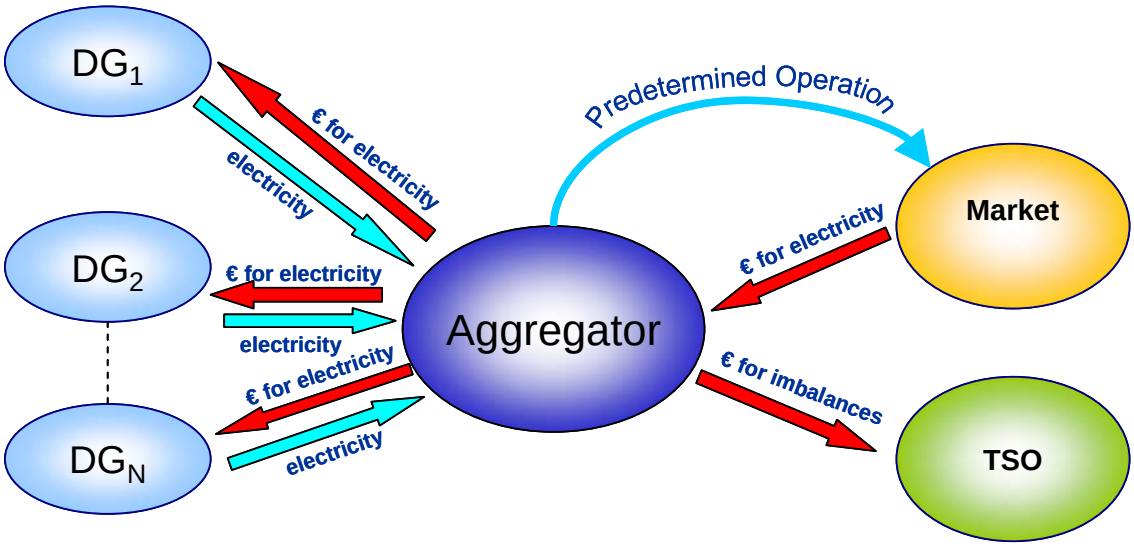

Figure 2.1 *Northern Scenario: reference case*

2. *Optimised wholesale market participation:* The Aggregator starts to act as a commercial VPP (CVPP) and assumes operational control over a number of flexible Woking CHP plants with a total flexible capacity of approximately 2.5 MW, installing enabling FENIX ICT intelligence. Moreover, the CHP plant owners concerned invest in suitably sized heat storage capacity to reduce significantly heat dumping. In doing so, the benefits of flexible operation of the CHP plants under VPP control by way of increased heat benefits. The CVPP switches the generating plants under its control into active (idle) mode when the sum of expected marginal power and heat benefits exceed (are less than) the marginal costs of running the plants (see Figure 2.2).

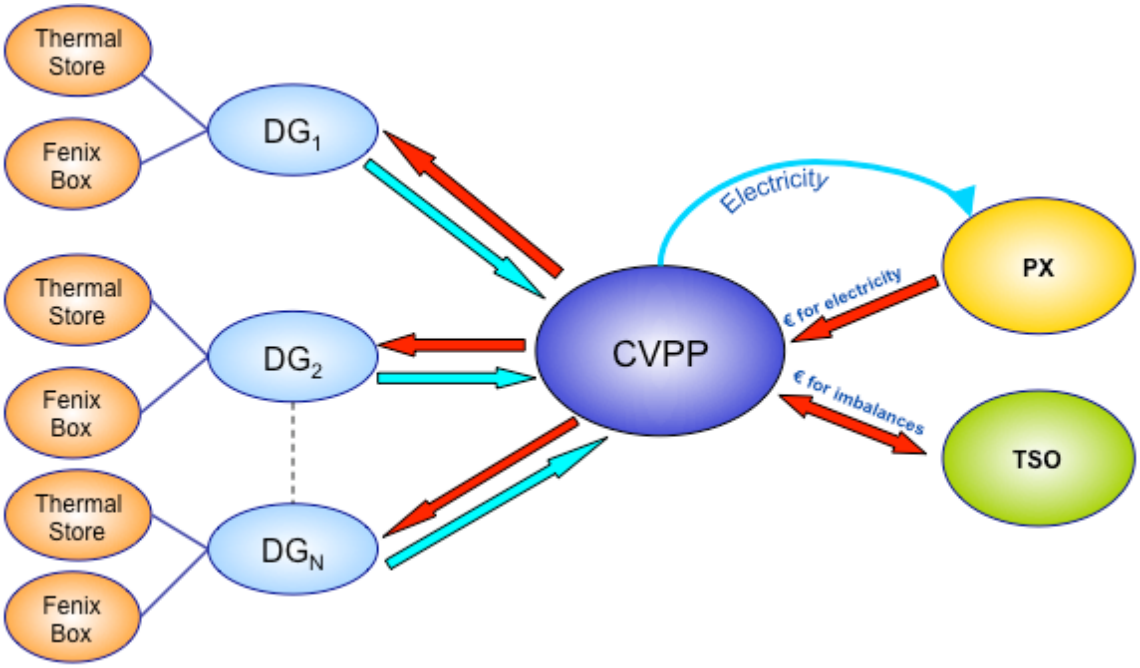

Figure 2.2 *Northern Scenario: optimised wholesale market participation*

3. *Balancing services to the TSO:* The CVPP continues to flexibly schedule to dispatch the generating assets under its control as in the case Optimised wholesale market participation. In this case, moreover the CVPP participates in the Balancing Mechanism (balancing mar-

ket), run by TSO (transmission system operator) NGC. The CVPP submits profitable bids (to switch off CHP plants scheduled to run) and offers (to switch on CHP plants scheduled in idle mode) to the TSO. When the TSO wants to use the balancing services of the CVPP, he calls on the CVPP to deliver as bid or offered. This case, Balancing services to the TSO, is incremental for the CVPP to case Optimised wholesale market participation and can yield him more money (see Figure 2.3).

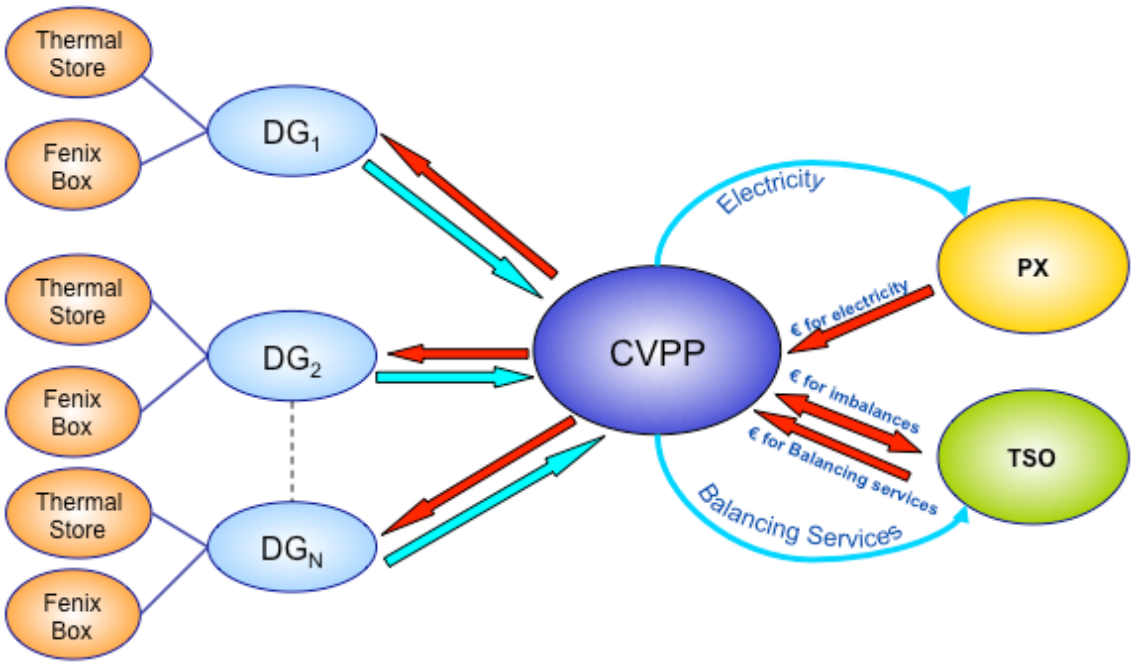

Figure 2.3 *Northern Scenario: balancing services to the TSO*

4. *Intra-day adjustment services to the Supplier:* Incremental to case Optimised wholesale market participation and as an alternative to case Balancing services to the TSO the CVPP offers profitable intra-day bids (to switch off CHP plants scheduled to run) and offers (to switch on CHP plants scheduled in idle mode) to the Supplier (see Figure 2.4). The Supplier will call on these intra-day services when he has run in a large unforeseen intra-day imbalance position with respect to the TSO run Balancing Mechanism and when he expects that calling on the CVPP's intra-day services saves him money, compared to imbalance settlement with the TSO. This case, i.e. Intra-day adjustment services to the Supplier, is incremental for the CVPP to case Optimised wholesale market participation and, therefore, can yield him more money than the latter case. Yet the CVPP must weigh going for case Intra-day adjustment services to the Supplier as an alternative for the case Balancing services to the TSO.

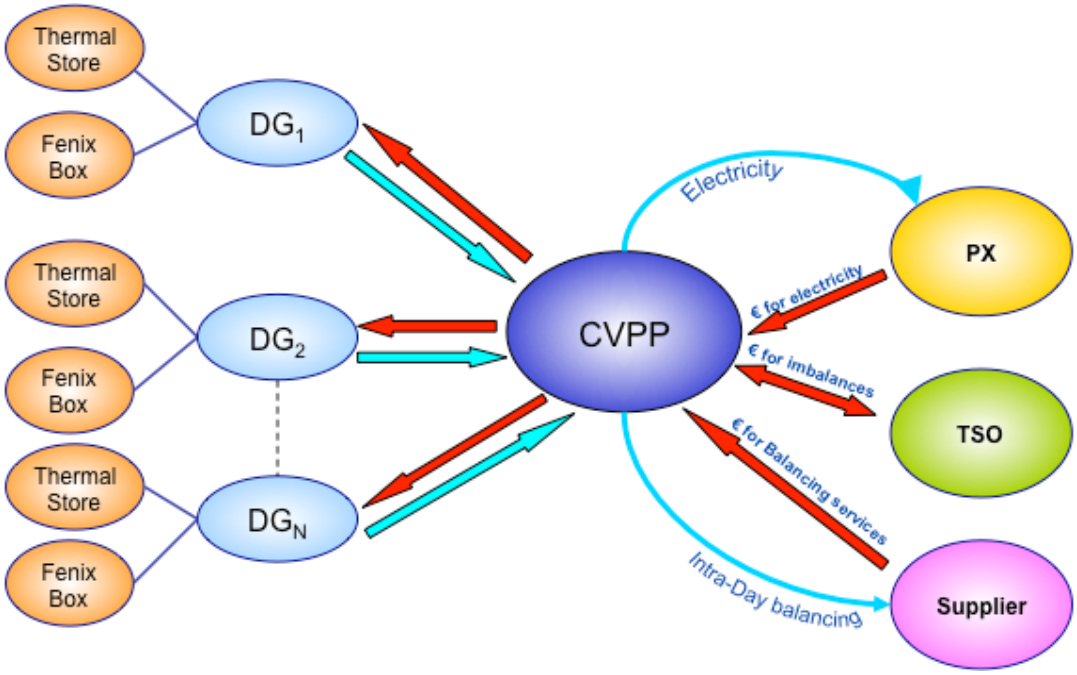

Figure 2.4 *Northern Scenario: intra-day adjustment services to the Supplier*

5. *Tertiary reserve services to the TSO:* The CVPP offers tertiary reserve services on a periodic tender call by the TSO for the provision of tertiary reserve services in certain pre-defined service time windows of the day for a certain 'season'. There are 6 'seasons' in a year. When the TSO accepts the CVPP's offer, (only) during the pre-defined service time windows the CVPP has to put the generating assets under his control in idle mode and be ready to switch on when called by the TSO to do so. During the service time windows, this case (Tertiary reserve services to the TSO) on the one hand and the three FENIX cases explained above on the other are mutually exclusive. Hence, the CVPP has to weigh as to whether Case 4 is potentially more rewarding than either one of the other FENIX cases (see Figure 2.5).

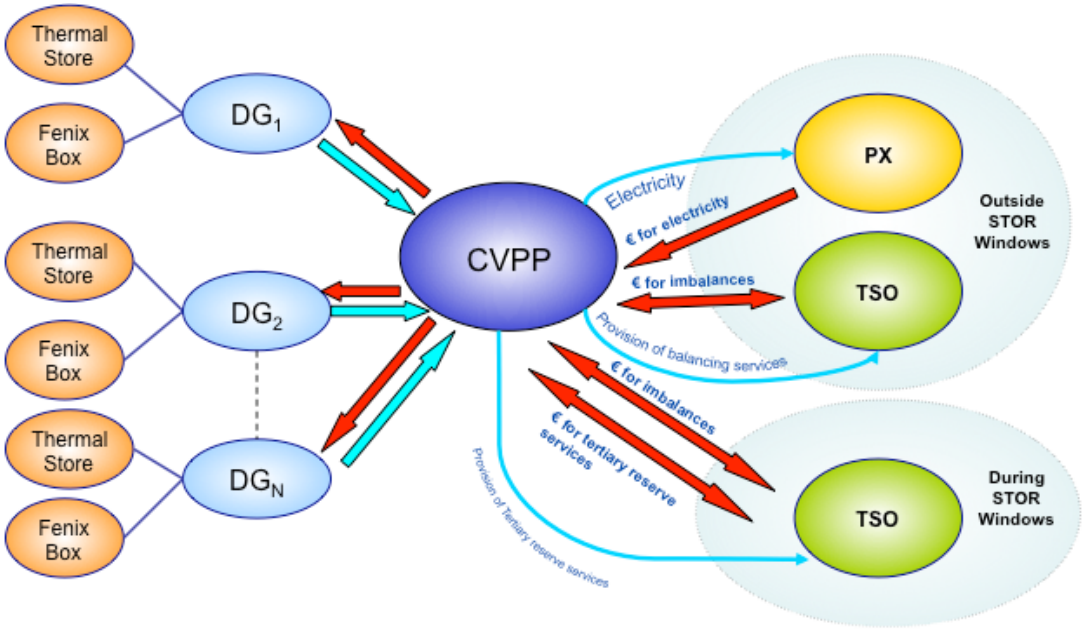

Figure 2.5 *Northern Scenario: tertiary reserve services to the TSO*

2.3 Southern Scenario

The DER portfolio considered in the Southern Scenario (SS) includes different technologies (CHP, wind, small hydro) and it is based on some real units located in Alava, whose total installed capacity is in the range of 150 MW_e out of which about 50% is flexible. More details about the Southern Scenario can be found in Aunedi *et al.* (2008). In order to model the different options that these DER have for trading their electricity, the reference case and four alternative cases were considered. The Southern Scenario cases are all incremental. Hence the first SS case is the reference case; first alternative case introduces new features, whilst all other features of the reference case still hold; the same applies for the second alternative case with respect to first alternative case, etc. As we have explained above, this is unlike some cases in the Northern Scenario Cases that are mutually exclusive.

1. *Reference case:* Each DER trades electricity on its own in the market and, hence, it completely bears the cost of its imbalances. This is the only option possible under present regulation in Spain, so it will be taken as the base case for comparison purposes (see Figure 2.6).

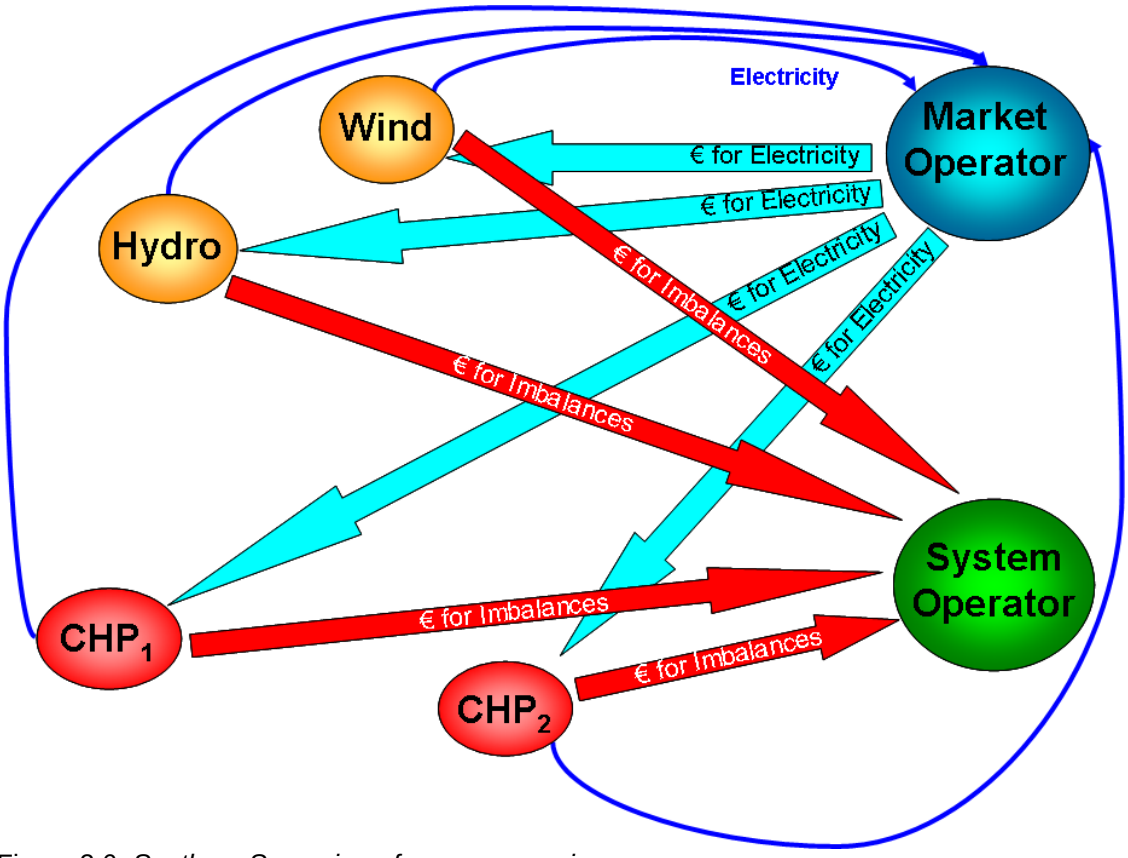

Figure 2.6 *Southern Scenario: reference scenario*

2. *Commercial aggregation:* The output of all DER units is sold together by an aggregator, i.e. (non-operational) commercial aggregation (See Figure 2.7). The extra value obtained is from the *portfolio effect*, so that through aggregation individual negative and positive imbalances are partially offset. This option would be possible today if CHP units would be aggregated together. However, the existing regulatory framework does not allow today commercial aggregation services to renewable generators.

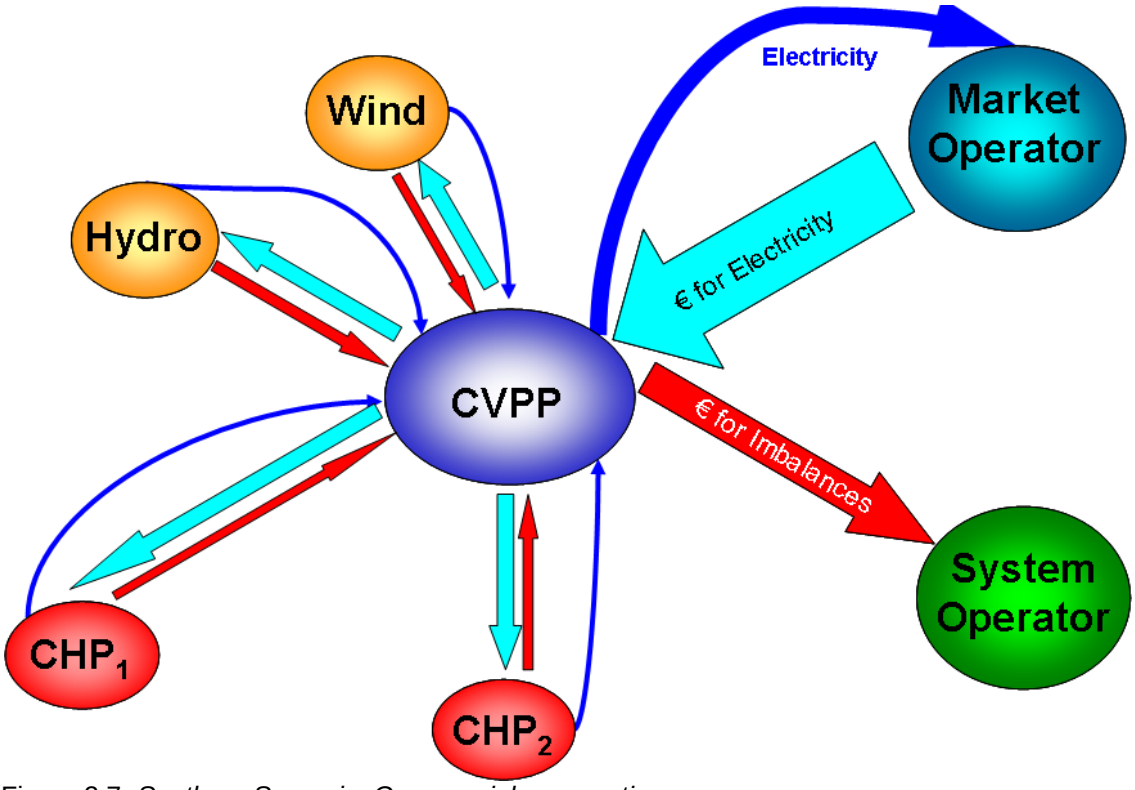

Figure 2.7 *Southern Scenario: Commercial aggregation*

3. *Optimised wholesale market participation:* DER units are aggregated commercially *and operationally* by a CVPP, so an imbalance reduction is obtained from the portfolio effect (see Figure 2.8). Besides, CHP units stop producing electricity (and heat) when the benefit of producing (difference between the price of selling electricity and the cost of producing) is lower than the cost of producing the required heat in ancillary boilers. When such a situation occurs, the CVPP stops the CHP and starts-up the boilers. *Note that no generation increases are performed as a result of high market prices; only generation is ramped down when market price is low.* The reason is that, in Spain, CHP plants must fulfil some Equivalent Electric Efficiency (EEE) requirements. Every time CHP units are ramped up or down their EEE is reduced, because they will not be producing useful heat and electricity at the same time (remember that no storage is used). Although for this case, an optimal operation which fulfils EEE requirements could have been done, the optimisations for the following cases would have had to consider much more constraints (if CHP ramped up in the day-ahead market, no upward balancing can be provided because there is no capacity left, but also if CHP ramped up two months ago, now no upward balancing can be provided because EEE will go below the legal threshold). As a result, the value of the additional services could have hardly been assessed. Therefore, instead of optimising the operation to increase incomes, such operation was improved, just by switching off the unit when the costs of producing was higher than the benefit of doing so.

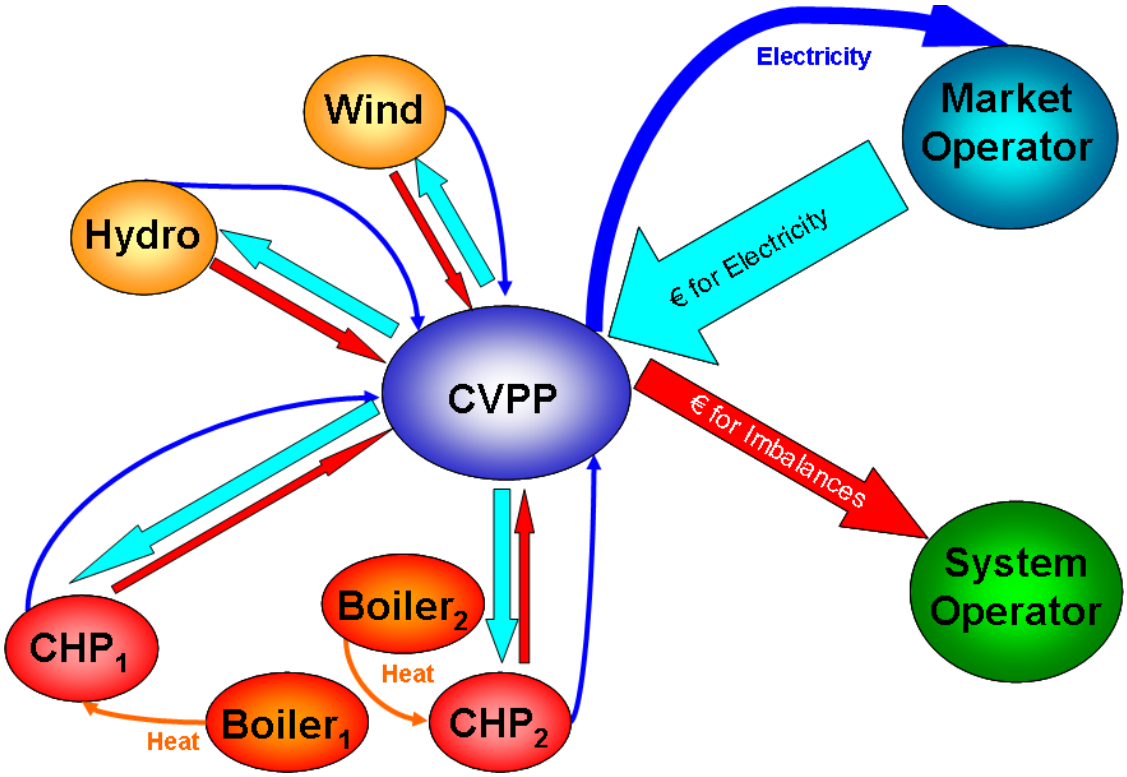

Figure 2.8 *Southern Scenario: optimised wholesale market participation*

4. *Active internal balancing:* In addition to benefiting from portfolio effect and replacing CHP units by separate boilers to meet fixed heat demand when the power market is not attractive, *CHP units can – upon advice by the CVPP operator - modify their electricity output (up or down) in order to reduce the total imbalance of the DER portfolio* (see Figure 2.9).

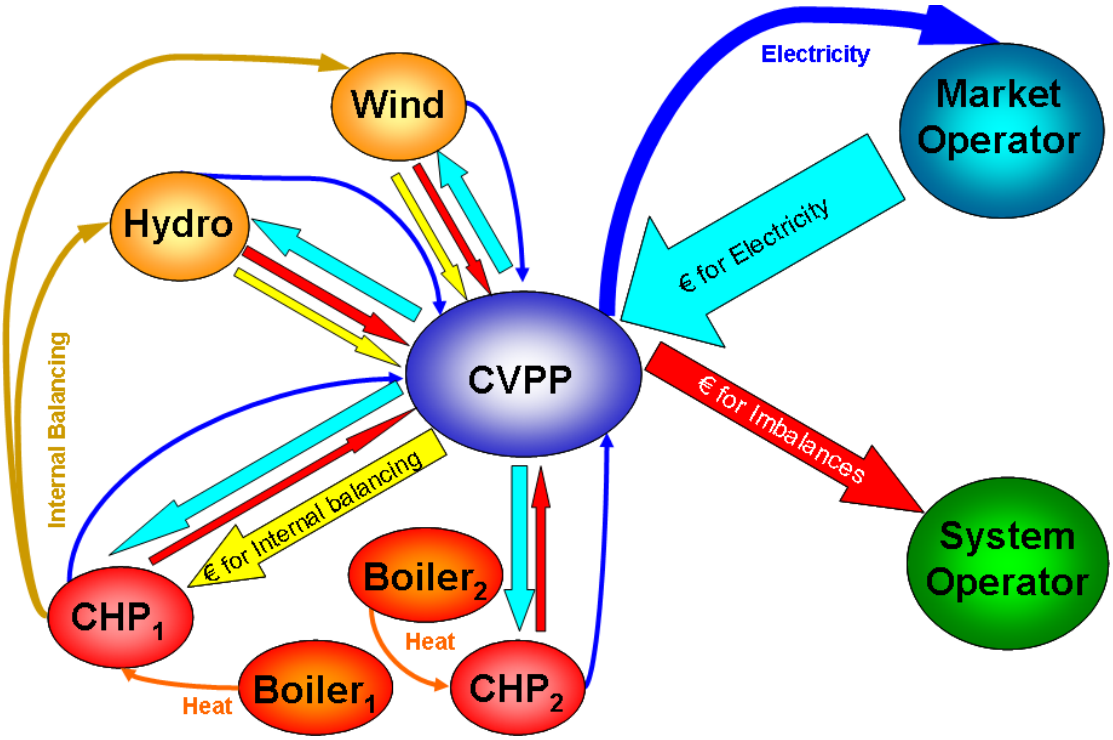

Figure 2.9 *Southern Scenario: active internal balancing*

5. *Balancing services to the TSO:* On top of the actions performed in the previous cases, CHP units provide balancing services to the TSO, thanks to the CVPP (see Figure 2.10). CHP units provide tertiary regulation, both up and down. They are remunerated for the operation, not for the availability.

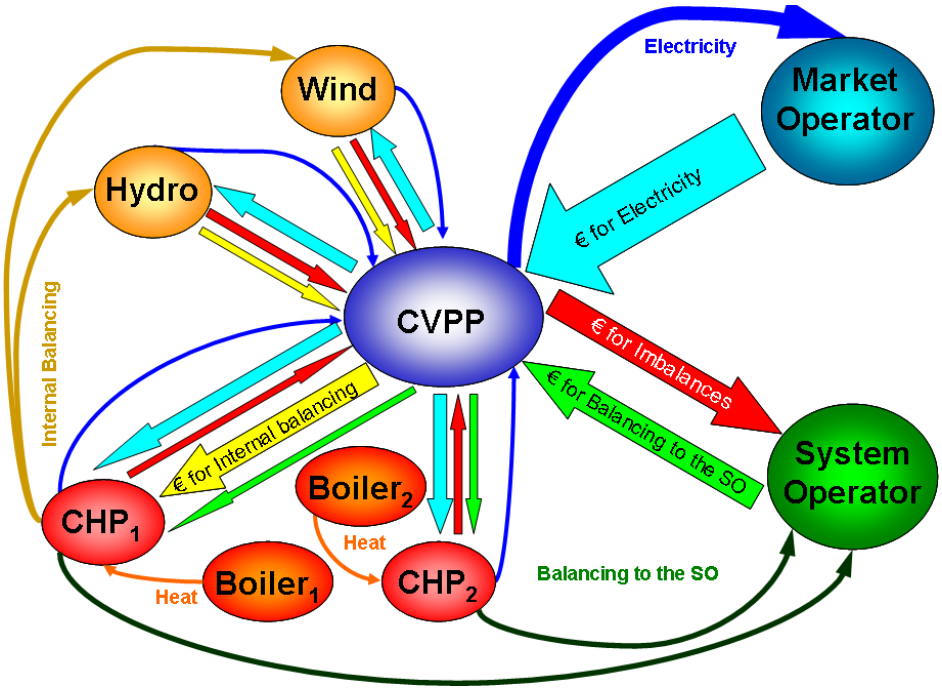

Figure 2.10 *Southern Scenario: balancing services to the TSO*

3. APPRAISING SELECTED FENIX APPLICATIONS: KEY RESULTS

3.1 Introduction

This chapter presents key results from the cost-benefit analysis of selected FENIX flexibility applications in the Northern and Southern scenario respectively. These applications have already been introduced in the previous chapter. This chapter starts with a brief discussion of the approach (Section 3.2). Next, a more detailed case by case overview of the CBA outcomes is given from both a system stakeholder and an aggregated system perspective: for today and in the future on a small-scale basis, as well as in the future with country-wide deployment of FENIX (Section 3.3). Then, the investor's perspective is considered, i.e. the aggregated net benefits of the FENIX applications concerned are assessed for business stakeholders that have to invest in it or to participate in it through enabling contractual relations (Section 3.4). Finally, the main results of socio-economic analysis focusing on external effects, i.e. socio-economic impacts of FENIX on economic actors outside of the electricity sector, are presented in Section 3.5.

Under Northern Scenario present-day and future conditions FENIX is a quite attractive proposition from the perspective of the stakeholders that stand to realize this concept. By far the most attractive FENIX applications are encompassed by case *Balancing services to the TSO* of the Northern Scenario, in addition to wholesale market participation of flexible DG. If only applied at the level of Woking, FENIX brings in Today on a yearly basis some € 56 / $kW_{flexible\ DG}$ of additional value to the key stakeholders that have to make FENIX happening. By year 2020 this amount is projected to even rise to some € 75 / $kW_{flexible\ DG}$. Results for case *Optimised wholesale market participation* show that - considered separately - wholesale market participation for flexible DG is the FENIX application that creates most value for the investors in FENIX. They also show that upscaling will modestly reduce the large value created by FENIX per unit of generating capacity governed by FENIX intelligence.

When each case is considered separately, for investors in FENIX the most value by far is created in the Southern Scenario by the application *Balancing services to the TSO*. Like in the Northern Scenario in the Southern Scenario, upscaling in the future will reduce the value creation per kW of flexible DG. Even so, also with upscaling the FENIX concept brings in handsome returns for investors in both Northern and Southern Scenarios.

3.2 Approach

The approach to assess the value of the FENIX applications for both the cases of the Northern and Southern Scenario consists of two steps. First, a reference scenario is developed against which the economic attractiveness of FENIX applications can be assessed. Next, distinct FENIX applications are introduced successively based on model simulations. For each application, the incremental cash flows with respect to the reference case are determined, i.e. for each stakeholder separately and on a system-wide level as well.

The net benefits of distinct FENIX applications are assessed from several perspectives, i.e. the perspectives of distinct network stakeholders, the consolidated network perspective, and the

societal perspective. In doing so it benchmarks incremental costs and benefits of distinct FENIX applications against those of the "without FENIX" reference case. The focus is mainly on incremental recurrent cash flows. That is, the cash flows pertain mainly to changes in operating costs and revenues relative to the reference case. Quantification of incremental net benefits on reduced/deferred investments in network reinforcement is extremely complex and very location-specific and has therefore been refrained from. In this report the impact of the application of FENIX concepts on the distribution network costs is addressed in a qualitative way in chapter 4 hereafter.

Our economic analysis focuses on the potential value creation by use of DER (DG) flexibility for commercial (market) applications. The impact on the character and profitability of the business model is considered for the following stakeholders:

- DG
- DG Aggregator / CVPP
- Supplier of DER concerned (Northern Scenario)
- TSO
- Large-scale generators
- Regulator (bonus payments: Southern scenario).

As FENIX does not consider demand-side flexibility, in our simulations the volume and value of energy deliveries to end-users remain unaffected. To not overly complicate the analysis we assume that distribution network tariffs and profits of the distribution system operator remains the same.

The aggregated net cash flow impact on all electricity-system stakeholders together represents the impact on the electricity system. A positive aggregate net cash flow impact at system level indicates that the electricity industry at large will profit from application of the FENIX concept: that is, efficiency benefits from better market functioning as a result from better market participation of DER and/or improved fuel efficiency / less losses at system level because DER substitute part of high-voltage level centralised generation. In practice, when FENIX will bring in more profits to the electricity industry, notably the regulated part of it, the regulator may intervene in the regulatory framework to pass on a major part of any system efficiency improvements to the electricity users. Such transfer mechanisms are beyond the scope of this analysis.

The socio-economic analysis considers the impact of the adoption of the FENIX concept on some major externalities, notably the overall fuel requirements of the electricity system (security of supply) and on the GHG emissions intensity of the electricity system. Figure 3.1 below brings out the system boundaries of the cost benefit analysis at system level.

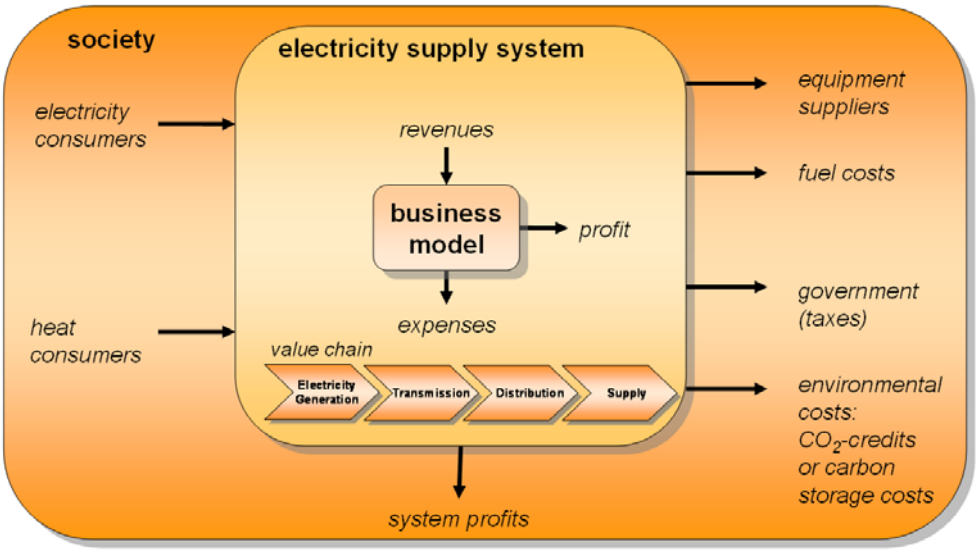

Figure 3.1 *Schematic overview of the system boundaries of the electricity supply system*

3.3 Stakeholder and system net benefits

The FENIX CBA simulations for both the Northern Scenario and the Southern Scenario regard a reference case against which the differential costs and benefits of four Alternative Cases on an annual basis were determined. The analysis included fuel costs, other recurrent costs (O&M: operation and maintenance) and investments in FENIX ICT facilities and, for the Northern Scenario, additional heat storage to optimise flexible deployment of CHP plants under operational CVPP control.[2] To not overly complicate the already complex CBA simulations, impacts on network costs were excluded from the quantitative CBA analysis framework. Hereafter we will present both for the Northern Scenario (NS) and the Southern Scenario (SS) results of the CBA simulations for:

- Annual value creation of FENIX applications Today (i.e. for respectively base year 2006 for the Northern Scenario and 2007 for the Southern Scenario) at small-scale level based on the Northern and Southern Demonstrations at Woking Borough and Alava respectively
- Annual value creation of FENIX applications in the future, i.e. year 2020, at small-scale level
- Annual value creation of FENIX applications in the future, i.e. year 2020, with up-scaling of small-scale level case study simulations to the national level, i.e. UK and Spain respectively.

3.3.1 Today

We will set out key results for the *Northern Scenario* first, whilst our explanation of key results for the Southern scenario follows in the second half of this section. We start out with a brief discussion of results per alternative case. Next we zoom in on the case that, according to our simulations, will create most additional value for electricity system stakeholders and the electricity system at large.

<u>Northern scenario</u>

Optimised wholesale market participation

The flexible CHP units are centrally controlled by a CVPP and are deployed on those half-hourly settlement periods when FENIX intelligence expects a net positive balance of marginal revenues (electricity sales, LEC i.e. market stimulation subsidies, and avoided marginal costs of running separate boilers to meet fixed heat demand) over marginal costs (O&M and fuel cost). These units are typically active when electricity prices are highest. This stands in contrast with the Reference Case where the small-scale CHP units concerned (gas motor units) are deployed most of the time at fixed hours during the day. Although the load factor of the units drops from 70 to 50%, this is more than compensated by deployment at rewarding high-price settlement periods that are most rewarding. During part of these periods the flexible units substitute the output of large-scale centralised production, whereas at typically low-price loss-making settlement periods for the flexible DGs their Reference Case production is substituted by production from centralised large-scale generators. Although the annual generation volume of the latter goes up and the generation volume of the flexible units go down, this is more than compensated by the flexible DGs running when they can make profits. The large-scale units tend to run more at less remunerative hours. Our model assumptions on the contractual framework make for a small negative net result for the CVPP and a small positive result for the supplier to the Woking Borough microgrid respectively while the large-scale producers stand to sustain a negative revenue impact from CVPP-controlled participation in the power market by the flexible DG. The net aggregated value creation impact at system level is positive.

Figure 3.2 brings out the impact of the case *Optimised wholesale market participation* on annual value creation in the electricity system, expressed in money of the day ($€_{2006}$) per unit of capacity of flexible DG. Note that the annual revenue impact on the TSO is not shown, as this impact tends to be negligible for all cases with positive settlement period results tending to be offset by

[2] In the Southern Scenario industrial CHP units were considered producing process steam. The much smaller CHP units considered in the Northern Scenario are to meet heat demand for space conditioning and water heating and dispose of heat storages. The latter application, as against the former, allows for flexible deployment of CHP units through the introduction of FENIX flexibility.

negative results in other settlement periods. The flexible DGs stand to gain annually € 33 per kW. On balance, also in the electricity system positive value is created to the tune of € 24.5 per $kW_{flexible\ DG}$. Given the fuel efficiency assumptions made in our model simulations, part of this relates to higher fuel efficiency at system level owing to more optimised deployment of DG, given Woking's fixed electricity and heat demand profiles over time. A second factor at work is improved market efficiency resulting from more optimised competition from the flexible DGs facing centralised generation.

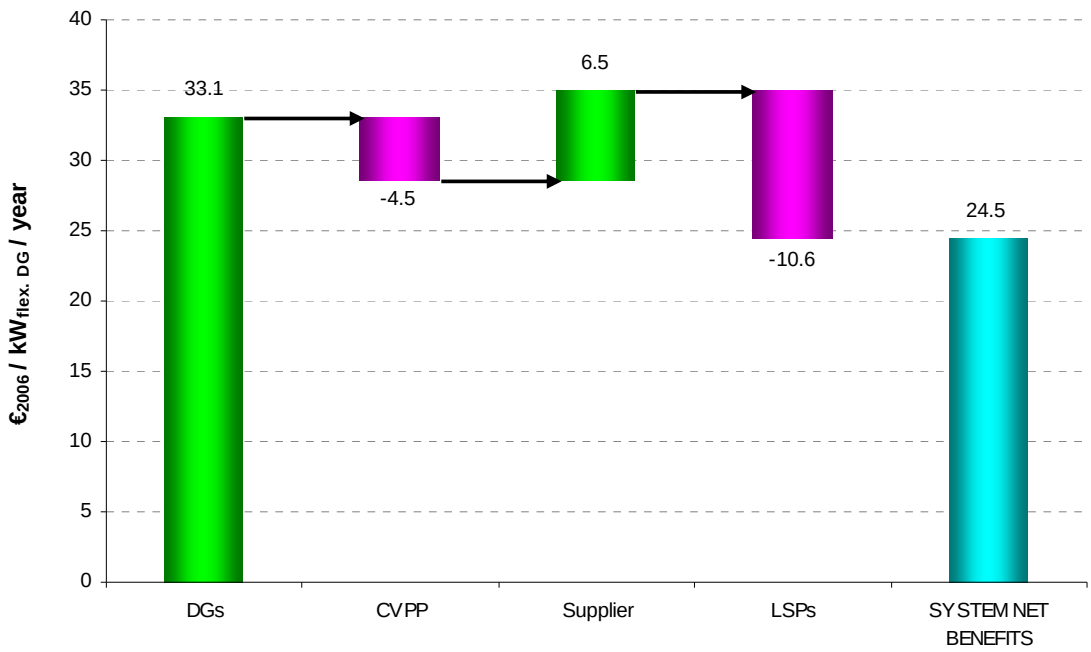

Figure 3.2 *Northern Scenario: net value creation by FENIX application optimised wholesale market participation for stakeholders and electricity system as indicated by simulations at small-scale level, year 2006*

Balancing services to the TSO

The case *Balancing services to the TSO* is incremental to the previous case (*Optimised wholesale market participation*). The CVPP brings out profit-making bids to the TSO to ramp down for settlement periods that he has contracted to deploy the flexible DG to generate for the power market. Conversely, for settlement periods the CVPP has notified the TSO that the flexible DG under his control will remain idle (because of expected losses when they would run instead) he submits profit-making offers to the TSO to ramp up. When the TSO accepts bids and offers of the CVPP this tends to further increase net revenues of the flexible DG on top of revenue gains resulting from *Optimised wholesale market participation*.

Our simulation model yields acceptance by the TSO of more bids to ramp down (at 850 settlement periods) than offers to ramp up (620 settlement periods). Our model outcomes indicate slightly higher revenues for the CVPP when Woking demand is met internally by generation of local DG. As annual local generation is reduced further somewhat, the CVPP's income is impacted likewise. Furthermore, the new entrant competition from flexible DG facing large-scale generators in the TSO-organised Balancing Mechanism negatively impacts net revenues of large-scale generators. Figure 3.3 brings out net revenue impacts explained above.

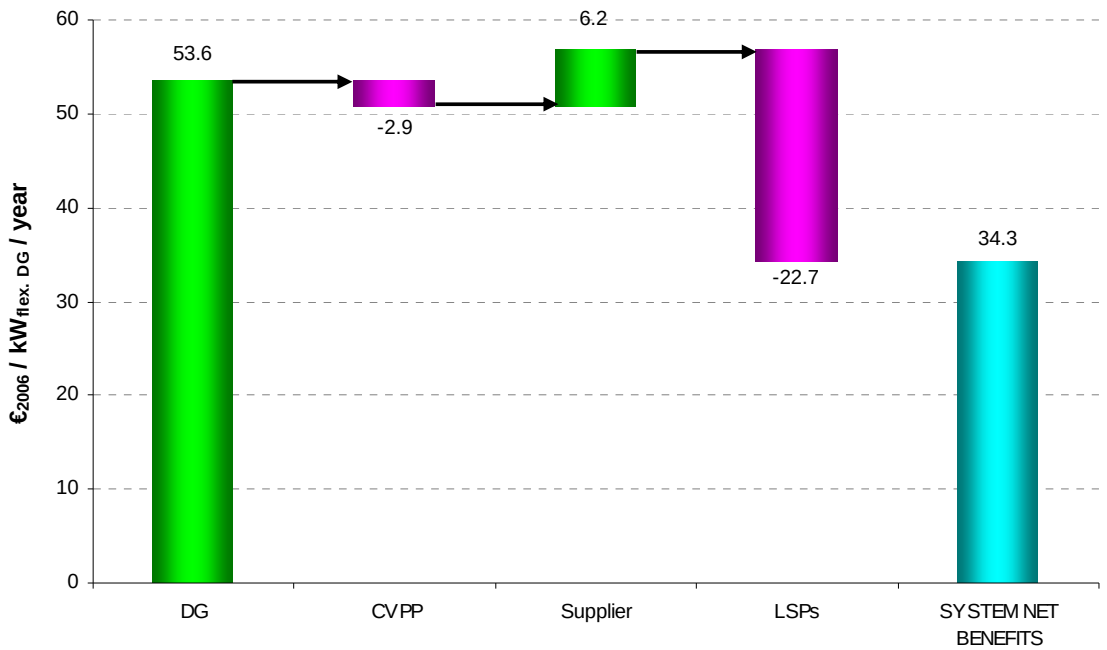

Figure 3.3 *Northern Scenario: net value creation by FENIX application balancing services to the TSO in addition to optimised wholesale market participation for stakeholders and the electricity system as indicated by simulations at small-scale level, year 2006*

Intra-day adjustment services to the Supplier

This case regards the integrated Supplier, serving Woking, who operates on top of his electricity supply business a low volatility generating portfolio as well. The Supplier seeks less costly imbalance cost alternatives in lieu of ex post imbalance settlement with the TSO when - due to contingencies such as unplanned outages with respect to his generating assets or unexpected demand surges - large intra-day imbalances would occur. The case *Intra-day adjustment services to the Supplier* is incremental to the previous case (participation in the power market by flexible DG controlled by the CVPP). The CVPP brings out profit-making bids to the Supplier to ramp down for settlement periods that he has contracted to deploy the flexible DG to generate for the power market. Conversely, for settlement periods the CVPP has notified the TSO that the flexible DG under his control will remain idle (because of expected losses when they would run instead) he submits profit-making offers to the Supplier to ramp up. When the Supplier accepts bids and offers of the CVPP this tends to further increase net revenues of the flexible DG on top of revenue gains resulting from *optimised wholesale market participation*. Note that the current case and the case *Balancing services to the TSO* are mutually exclusive.

The integrated Supplier, EDFE, serving Woking currently has a low volatility generating portfolio with a low volume of wind power generating assets. We have simulated the FENIX application intra-day adjustment services to the Supplier in a situation in which his generating portfolio, notably because of renewable variable generation assets especially wind power, has higher volatility than is the case at present with EDFE. We did so to more realistically consider the impact of FENIX for balancing responsible stakeholders with generating portfolios containing significant wind power assets. [3]

The number of times the Supplier accepts intra-day adjustment bids and offers from the CVPP depends on the number of times unexpected extreme intra-day events occur to the Supplier's generation and supply business. Moreover, his expectations on the imbalance settlement costs

[3] Originally, two variants of case 3 existed, differing with respect to the imbalance position of the Supplier. For this report, the variant with high imbalances is selected, which reflects a portfolio with a lot of intermittent renewables. This variant is deemed most realistic in the 2020 situation.

and the contractual arrangement with the CVPP on the provision of intra-day adjustment services play a role. Beforehand it would seem plausible that relatively few times the Supplier will call on the CVPP to provide intra-day adjustment services. Indeed, our simulation model yields acceptance much less calls by the Supplier in the present case than by the TSO in the previous case, that is to ramp up on a yearly basis in 463 half-hourly settlement periods and to ramp down in 95 settlement periods. Our model results suggest that the flexible DG can increase their net revenues further on top of net revenue gains from participation - with CVPP generated FENIX intelligence - in the power market. But the increase is less than offering balancing services to the TSO. The Supplier stands to gain from this FENIX application as he can reduce his total imbalance costs by partial substitution of real-time TSO balancing by calling for intra-day adjustment services to be delivered by CVPP-controlled flexible DG. Figure 3.4 brings out net revenue impacts explained above.

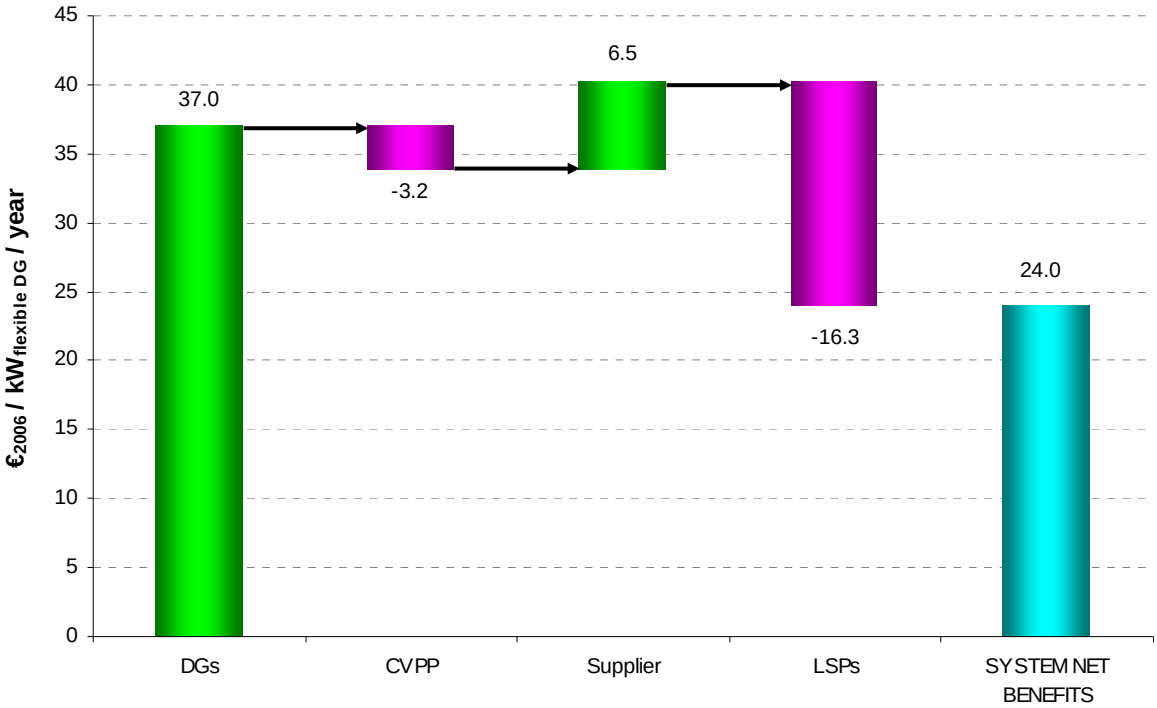

Figure 3.4 *Northern Scenario: net value creation by FENIX application intra-day adjustment services to the Supplier with high volatility generating portfolio in addition to optimised wholesale market participation for stakeholders and the electricity system as indicated by simulations at small-scale level, year 2006*

Tertiary reserve services to the TSO

In the fourth case study of the Northern scenario, CVPPs are used for the provision of non-automatically activated reserve services. Reserves are selected from ancillary services for three reasons: (i) this kind of service is not location-dependent i.e. can be provided all over the power system area; (ii) besides, involvement of the TVPP is not necessary, preventing additional complexity in case modelling; (iii) reserve services are one of the few services contracted via market arrangements, making the provision of reserves more accessible and transparent and suggesting that the market volume is considerable; and (iv) provision of secondary and tertiary reserves figures among the most valuable services: see literature review of Jansen et al. (2007).

It concerns so-called STOR (Short Term Operating Reserves) services. At certain times of the day the TSO needs access to sources of extra power, in the form of either generation or demand reduction to be able to cope with a deficit in supply (National Grid, 2008a). This can be caused by either unexpected generation unavailability or under-forecasted demand compared to the realized one. A STOR provider must be able to:

- Offer a minimum of 3 MW or more of generation or steady demand reduction (this can be from more than one site);
- Deliver full MW within no more than 240 minutes since receiving instructions from National Grid;
- Provide contacted-MW for at least 2 hours when instructed.

Although the under study portfolio does not completely satisfy the capacity requirement, the latter is relatively low and it can be foreseen that it is very likely that VPPs will have a considerably greater size.

The so-called committed STOR service contracts are signed between the National Grid and the respective units in one of the 3 tenders that are organized by the National Grid in every financial year (i.e. from April to March of next year). Every year is divided into 6 seasons, not necessarily of the same duration. For every day within a season, 2 (or 3) windows[4] are defined, during which the National Grid requires availability of the contracted STOR units. Generally, these windows coincide with the periods of high demand (e.g. between 07:00 and 13:00). According to the terms and conditions of a committed contract, the contracted unit is required to be available at all windows within the season(s) for which it has been contracted.

Every contract is characterized by two payment elements; an availability and utilization payment, which are unique (pay-as-bid system). These two elements are part of the offer made by the unit and at the same time the basic criterion on which the National Grid decides whether to accept or reject an offer. The availability payment, measured in £/MW/h, is made available to the contracted unit for all the hours that it reserved its contracted capacity, in order to provide STOR services to the TSO if needed. The utilization payment, measured in £/MWh, corresponds to the energy delivered by the contracted unit to the National Grid in the context of STOR. The two prices can differ from season to season but they remain constant within a season.

For the simulation purposes, it is assumed that the CVPP offers the nominal DG capacity and that the availability and utilization prices are equal to the average availability and utilization prices of the accepted offers of tender 1 for the year 2007/08; that is 6.21 £/MW/h and 228.41 £/MWh respectively (data retrieved from annual STOR report for year 2007/08).

We assume that flexible DG, controlled by Woking CVPP, are always available to provide reserves to the National Grid during the predefined STOR windows. In other words, the operational status of the DG is automatically set at "OFF" during the STOR windows (e.g. between hours 07:00 and 13:00, and hours 19:00 and 22:00 during the 1st season, which lasts from April 1st to April 28th). Only when, and for as long as instructed by the TSO to provide output will their operational status change. *Most favourable results so far are indicated for the case Balancing services to the TSO. Therefore, for the time of the day outside the STOR windows it is assumed that Woking DG participate in the Power Exchange and Balancing Mechanism markets (conform the just mentioned most profitable case)*. It should be noted that no distinction has been made between weekdays and non-weekdays with regard to STOR windows for modelling simplification.

Regarding the utilization of the DGs for the provision of STOR, the average utilization per MW in 2007/08 was around 50 hours/year. We have simulated two sub-cases: one with a utilization rate of 50 hours/year and another with a utilization rate of 80 hours/year. These values cover a range within which the actual utilization rates are likely to fall.
The simulations with these two alternative utilization rates both showed substantial decrease in the net revenues for stakeholders key to make FENIX to become reality, with the low utilization case for STOR services the largest decrease. The deterioration in net revenues applies in particular to flexible DG. This great difference can be explained by the fact that the DGs are reserved for a great part of the day for provision of STOR power (e.g. in season 1, the total dura-

[4] Generally, 2 windows are defined in a day, a morning and a night one. Only during these windows the contracted parties need to be available to the National Grid.

tion of the 2 STOR windows is 9 hours). Not only DGs cannot participate in the rest of the markets during these hours, but also these hours are the peak ones, as explained above. This implies that the greatest potential for profits is not exploited, since the latter lies within these hours (the highest electricity prices are observed during peak hours). Hence, not only are DG deployed appreciably less during STOR windows, there net revenues (including utilization payments) diminish even more in relative (percentage) terms. The availability payments fall short by far to make up for this. The revenue base of the CVPP also shrinks with lower deployment of flexible DG during STOR windows. In contrast, the Supplier earns more than in Case 2 (but much less more than flexible DG and the CVPP lose out), as the Supplier is exporting more power to Woking loads.

Because of the robustly negative nature of the results of the present case for FENIX business stakeholders, we will refrain from presenting this FENIX application in further detail.

Southern Scenario

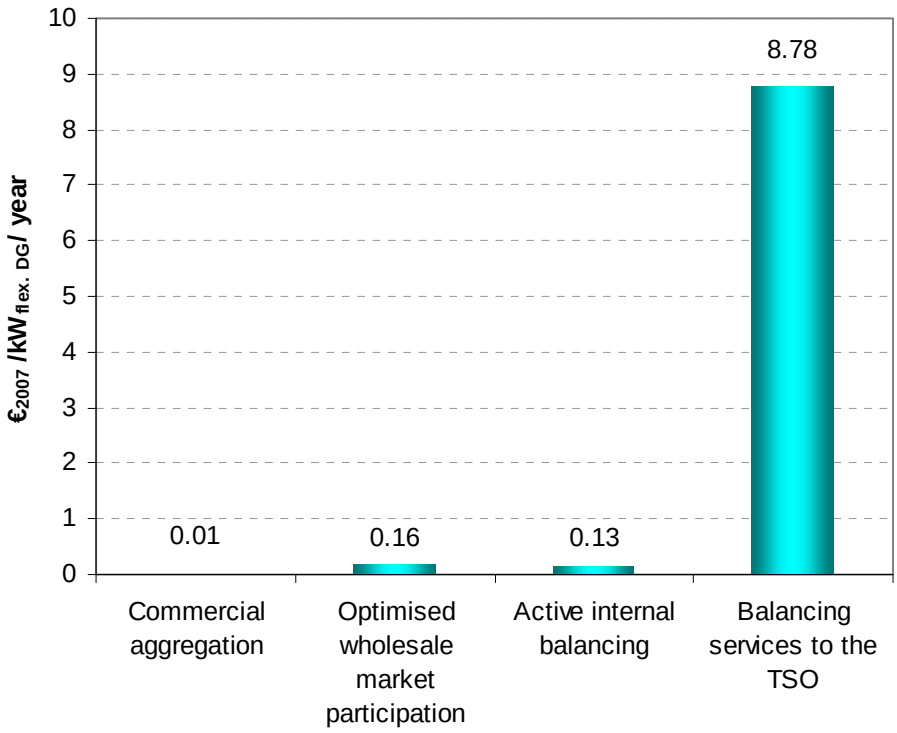

Figure 3.5 *Southern scenario: system benefits in the SS for the different cases, today*

These system net revenues i.e. the value of the FENIX concept can be attributed to the stakeholders for the different cases. This exercise provides valuable insights in the constituents of the value originating from the FENIX concept.

Optimised market operation
System benefits increase, because CHP generation is replaced by more efficient central generation (mostly renewable or nuclear) during times with low market prices, while concurrently boilers are deployed for meeting the industrial heat demand.

Active internal balancing
The slight loss of profit for RES in the case *Active internal balancing* is due to the investments in internal balancing which do not fully outweigh the additional resolving of imbalances by internal balancing.

Balancing services to the TSO
Figure 3.5 shows that the provision of balancing services to the TSO by efficient CHP units is the most attractive case for the system. It results in an increase of DER and CVPP net revenues as well as bonus savings, and compensates fully for the additional investment costs for enabling the provision of balancing services by CHPs.

Clearly in this *case the benefits to be shared between DER and the CVPP are the highest, reaching an annual amount of € 20.42 for each flexible kW DG included in the portfolio* (see Figure 3.6 below). There are also some *savings in bonus payments*, because DER are providing more downward than upward balancing, i.e. they produce less electricity and, hence, they receive less money for the bonuses. *Central producers* do not earn as much as in base case, because DER are replacing them in providing balancing services. All in all, the *annual system costs are reduced by € 8.78 /kW$_{flexible\ DG}$*, which saving can be passed through to consumers by reducing their taxes, T&D tariffs, et cetera.

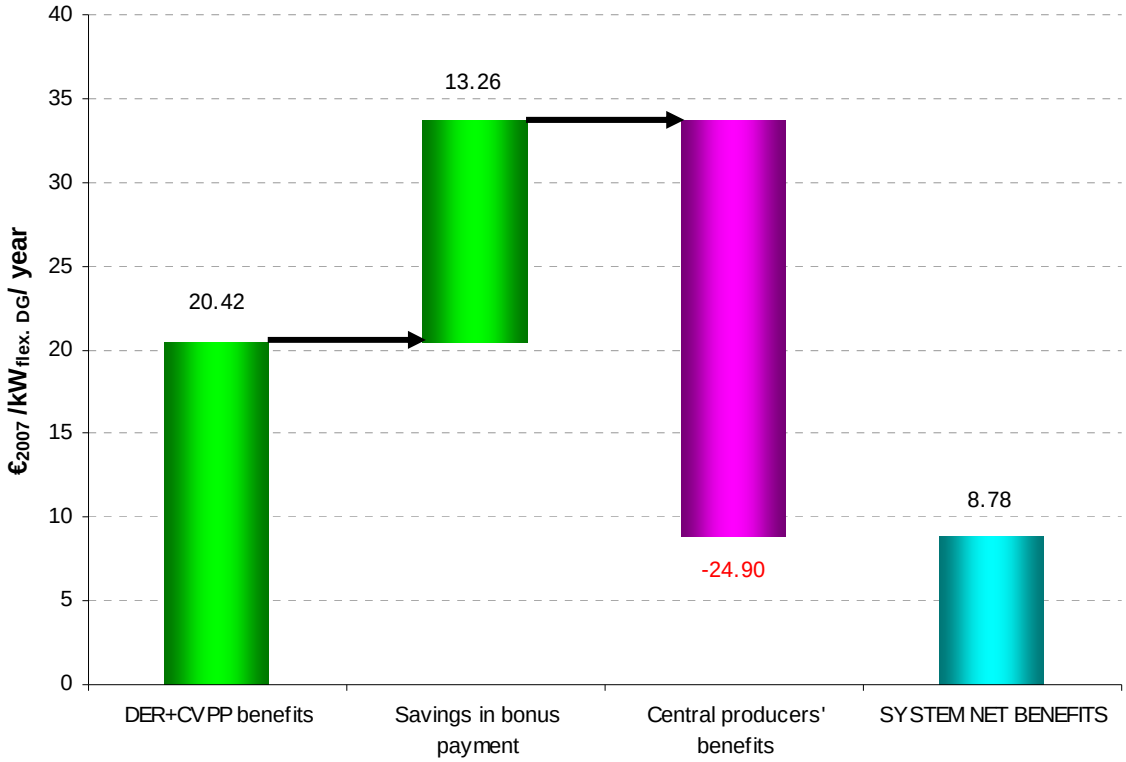

Figure 3.6 *Southern Scenario: net value creation by FENIX application balancing services to the TSO in addition to active internal balancing and optimised wholesale market participation, for stakeholders and the electricity system as indicated by simulations at small-scale level, year 2007*

The most beneficial case for *CHP unit owners* is Case 5 (see Figure 3.7), while both Case 4 and Case 5 are equally attractive for *RES unit owners* (see Figure 3.8).

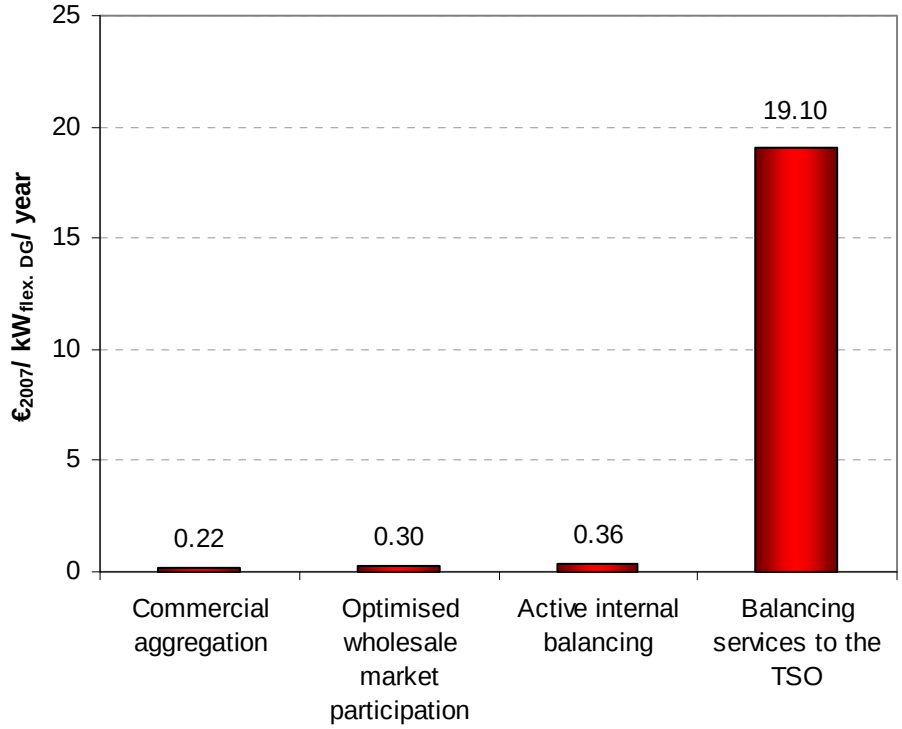

Figure 3.7 *Southern Scenario: net benefits for CHP units for the different cases, today*

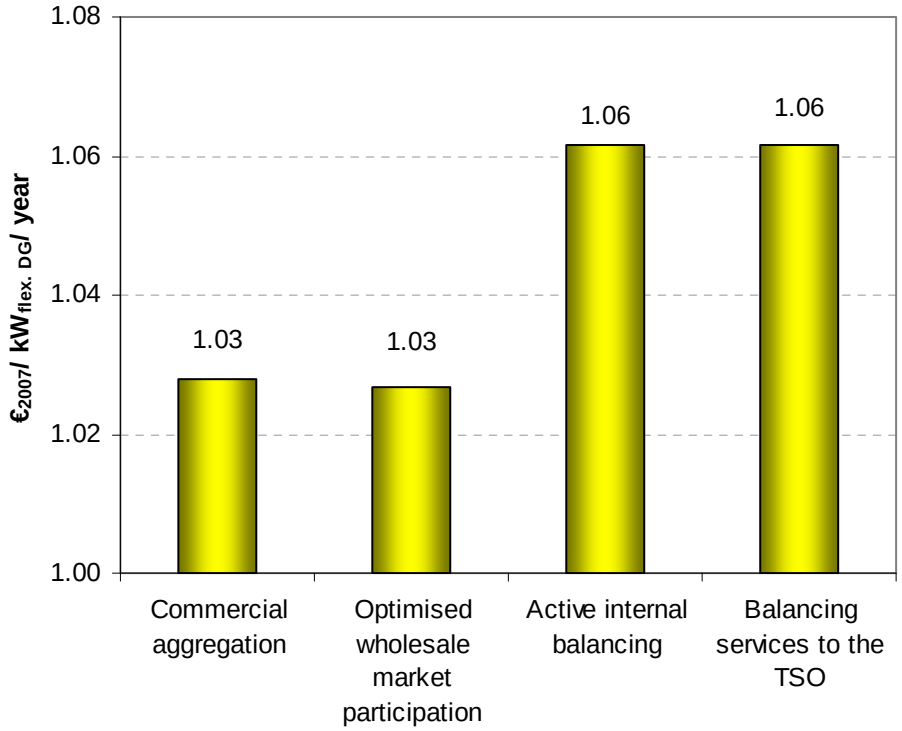

Figure 3.8 *Southern Scenario: net benefits for RES units for the different cases, today*

3.3.2 In the future

Northern Scenario

All FENIX applications show a higher system benefit than the reference case. Trends are the same in both 2006 and 2020 FENIX cases for DGs and system. DG net revenues increase in all cases while the same holds for the system apart from the last case (offer of tertiary services). System net revenues increase mainly due to higher expected electricity and balancing prices in 2020. Besides a number of other key parameters including gas price, price volatility of electricity and balancing prices, capacity price, and forecast errors have been adjusted in line with literature and expert estimations for 2020. Hereafter we present results case by case.

Optimized wholesale market participation

The *system* benefits increase compared to the reference case, due to the significant increase of DG net revenues and to a lesser extent CVPP and Supplier net revenues. This increase more than offsets the decrease of the large scale generators net revenues, showing that the system in total would gain significantly in 2020 like in 2006 from the optimized wholesale market participation of flexible DG (see Figure 3.9). This optimization of flexible DG wholesale market participation is enabled by the FENIX flexibility introduced in this case i.e. operational control of CHP units by FENIX boxes.

The net benefits for *DG* increase compared to the Reference Case, since high expected electricity prices induce higher CHP production (increase of total operating hours of CHP units). The total export volume increases with about 25%. Besides, the presence of thermal storage facility enables Woking CVPP to schedule CHP dispatch at half-hourly settlement periods with highest day-ahead prices. This stands in stark contrast to the Reference Case, where Woking exports also occur at night. The benefits of flexible operation of the CHP units exceed the additional costs, which encompass storage investment cost among others.

As opposed to the 2006 case, *CVPP* profits increase significantly due to the increase of the handling fee from DGs. The latter is changing proportionally to the revenues from power sales from DGs to the market, which increase due to higher electricity market prices in 2020. The amount of money obtained from handling fees further increases due to the rise of the handling fee from 3% to 5%, since the CVPP aggregates both operationally and financially in FENIX cases instead of only financially. In the 2006 case, due to the operational optimization the amount of electricity to be handled decreased compared to the reference case, resulting in higher electricity imports from the supplier and concomitant higher handling fees to be paid to the supplier.

For similar reasons *Supplier*'s net revenues also increase. Handling fees from CVPP increase, due to increases of both imports and exports. This is in full accordance with the 2006 case results.

LSPs' net revenues decrease as their operation is limited to hours with relatively low electricity prices. In hours with higher electricity prices large scale generators' production is replaced by production of small scale distributed generators. This is also in accordance with the 2006 case results.

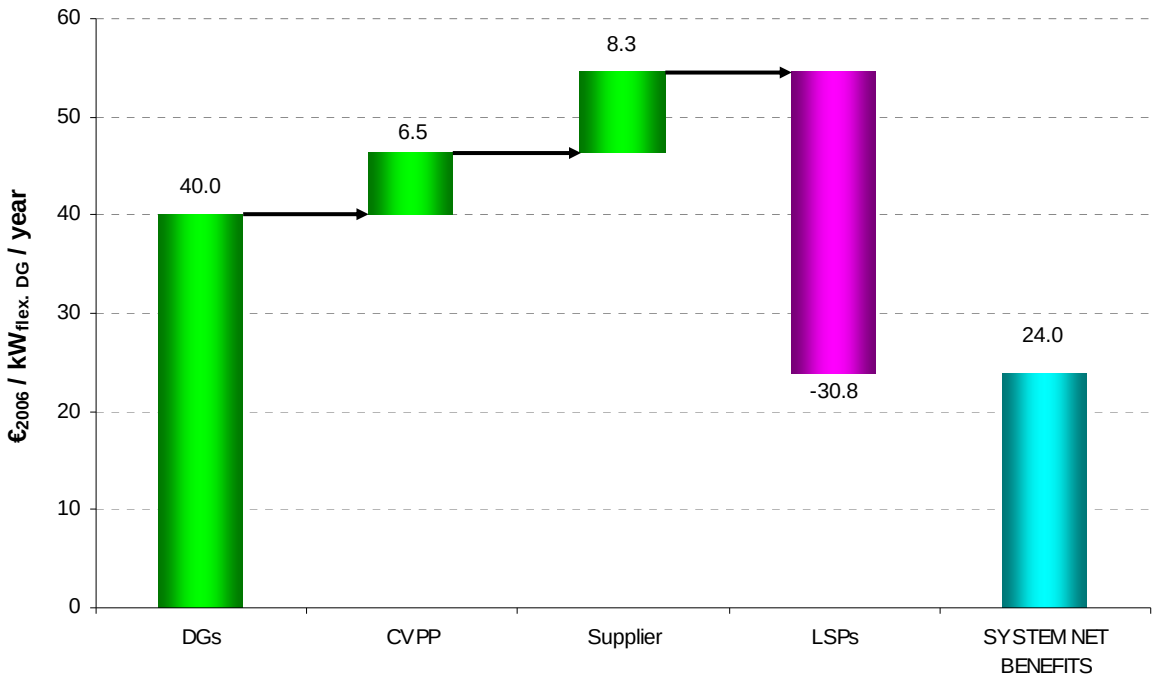

Figure 3.9 *Northern Scenario: net value creation by FENIX application Optimised wholesale market participation for stakeholders and the electricity system as indicated by small-scale simulations, year 2020*

Balancing services to the TSO
This case shows the highest net benefits for the *system*, due to the significant increase of mainly Woking DG net revenues. Besides CVPP and Supplier net revenues increase as well. Like in 2006, this shows that the system in total would gain significantly in 2020 from the introduction of FENIX flexibility in the day-ahead and TSO balancing market concurrently. Large scale generators lose again from the introduction of FENIX flexibility (see Figure 3.10).

Overall profitability of *Woking CHP generators* increases to approximately € 60 /kW capacity installed. This is caused by higher electricity and balancing market prices in 2020 compared to 2006, inducing higher CHP production (increase of total operating hours of CHP units) both for production on the day-ahead and balancing market.

As opposed to 2006, in 2020 the profits for *Woking CVPP* are assumed to increase due to higher power exports. These higher exports originate from the increase of DG production in 2020 compared to the reference case, while in 2006 DG production decreases. Although the need for imports also increases slightly, and therefore the handling fee passed through to the Supplier from the load, the additional handling fee revenues from exports exceed the higher handling fee costs from higher imports. As a result CVPP net revenues increase.

For similar reasons *Supplier*'s net revenues also increase. Handling fees from CVPP increase, due to the higher amount of electricity to be passed through from CVPPs to both electricity and balancing market. This is in full accordance with the 2006 case results.

The net revenues of the *large scale producers* decrease considerably. Like in 2006 production from large scale generators is replaced by production from DG during hours with higher DA prices. Moreover, large scale generators are replaced in the balancing market as well, causing negative net revenues.

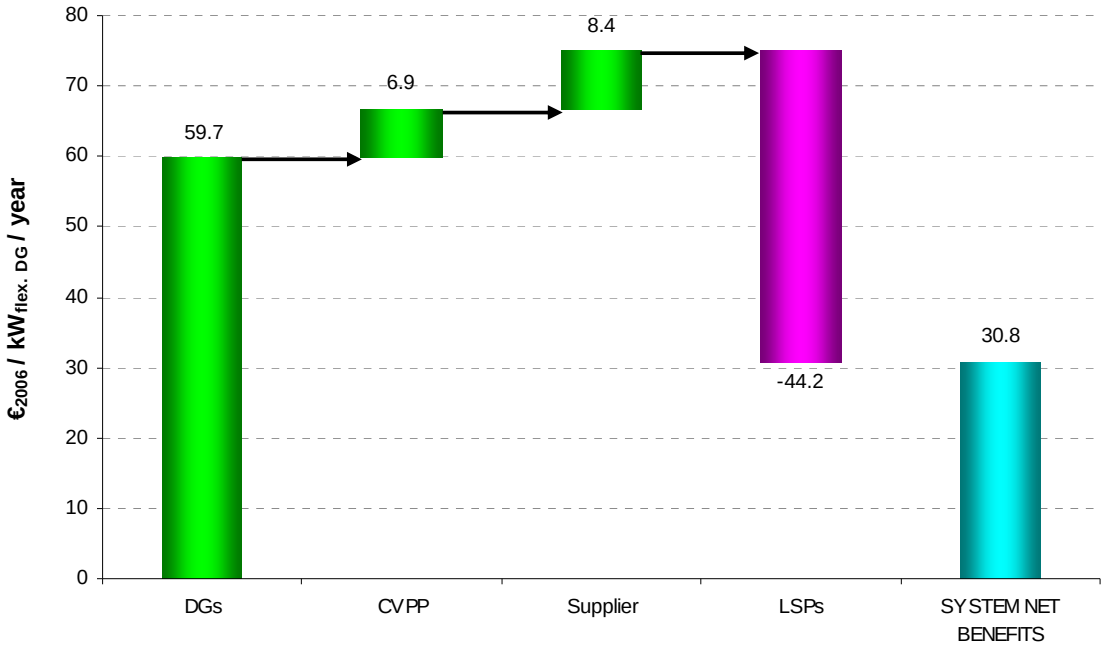

Figure 3.10 *Northern Scenario: net value creation by FENIX application balancing services to the TSO in addition to optimised wholesale market participation for stakeholders and the electricity system as indicated by small-scale simulations, year 2020*

Intra-day adjustment services to the Supplier
Results of the simulation of Case 3 in year 2020 are shown in Figure 3.11 below. From this figure, the following can be inferred:

The *system* net revenues rise compared to the Reference Case, especially due to the significant increase of Woking DG net revenues. Besides CVPP and supplier net revenues increase as well. Like in 2006, this shows that the system in total would gain significantly in 2020 from the FENIX flexibility introduced in the TSO balancing market. Large scale generators lose again from the introduction of FENIX flexibility.

Woking DGs' net revenues increase with about € 43.8/ kW capacity installed. Woking DGs provide mainly upward balancing services. This is expected, since the marginal costs of CHP units are relatively low and hence there is little scope for downward balancing. The overall settlement periods that Woking DGs provide balancing services is significantly lower compared to Case 2, as in this case their marginal cost is compared against average balancing prices and not highest offers/lowest bids.

The net revenues of *Woking CVPP* increase with € 6.5/ kW capacity installed. Again this is caused by the higher amount of electricity to be exported from DGs to the markets. CVPP profits increase due to the fees for the provision of upward and downward balancing services.

The net revenues of the *Supplier* increase with € 10.7/ kW capacity installed, for the same reason as the increase in profits for the CVPP; the supplier earns higher handling fees due the higher amount of electricity to be passed through to both electricity and balancing market. This is in full accordance with the 2006 case results.

The net revenues of the *large scale generators* diminish with € 40/kW per year. On the one hand, their deliveries increase. Like in earlier FENIX cases, production from large scale generators is replaced by production from DG during hours with higher DA prices This is in full accordance with the 2006 case results.

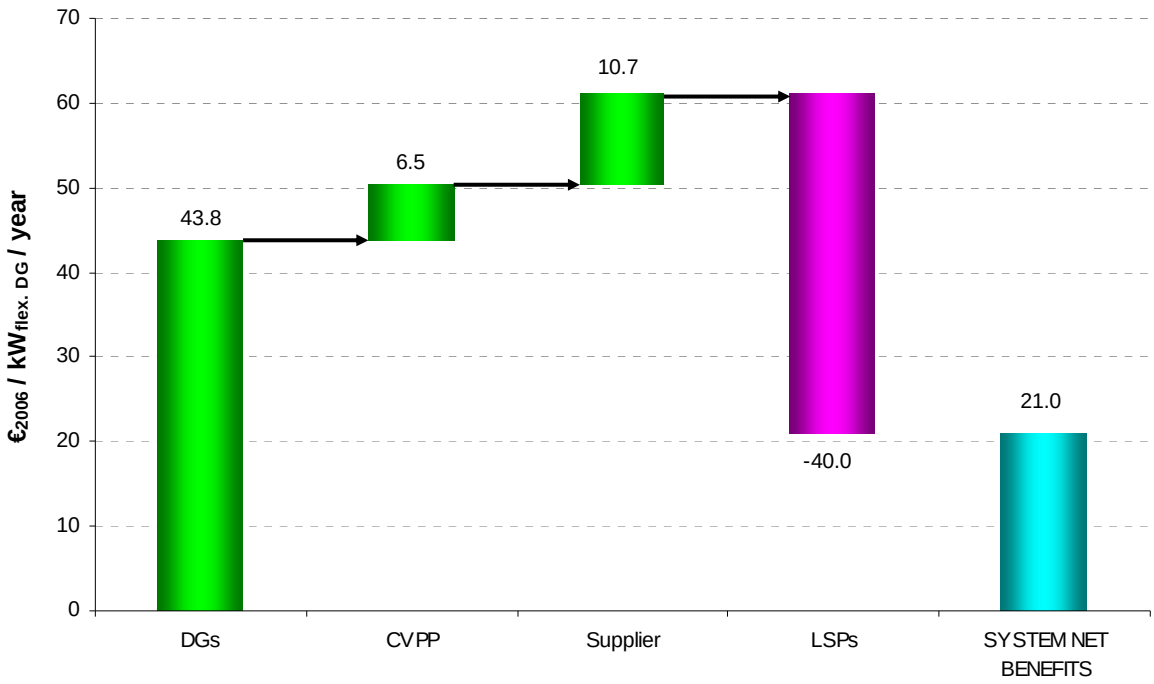

Figure 3.11 *Northern Scenario: net value creation by FENIX application intra-day adjustment services to the Supplier with high volatility generating portfolio in addition to optimised wholesale market participation for stakeholders and the electricity system as indicated by small-scale simulations, year 2020*

Tertiary reserve services to the TSO

The *system* net revenues rise marginally compared to the reference case. This shows that the system in total would gain in 2020 from the FENIX flexibility in the provision of STOR services. The non-negligible increase of net revenues of DG and supplier is nearly fully compensated by the decrease of the net revenues of the large scale generator and CVPP. Contrary to the 2006 situation, the introduction of provision of tertiary reserve services (STOR) by Woking DG delivers higher system results. This can be explained by the relatively high assumed mean capacity price value in 2020 as well as the higher price volatility assumed.

However, for two reasons we refrain here from a further elaboration of this case. Firstly, the uncertainties with respect to expectations, although well-founded in literature and expert estimates, make it a bit unclear whether in practice the system net revenues will be positive (also negative values fall within the reliability interval). Secondly, the system net revenues increase only marginal while other cases show clear positive results.

Southern Scenario

Figure 3.12 shows the system net revenues of these cash-flows for the different alternative cases. System savings in 2020 are higher than for today (2007). This increase of system savings is entirely due to the increase of DER+CVPP benefits. In the future, especially CHP units will be earning more money, as price variations in the market will be higher, even if gas prices also increase and some units see reduced bonuses. On the contrary, RES units will be earning less, since they will receive no bonus in 2020. The overall increase of DER+CVPP benefits more than compensates for the decrease of savings in bonus payments and central producers' benefits.

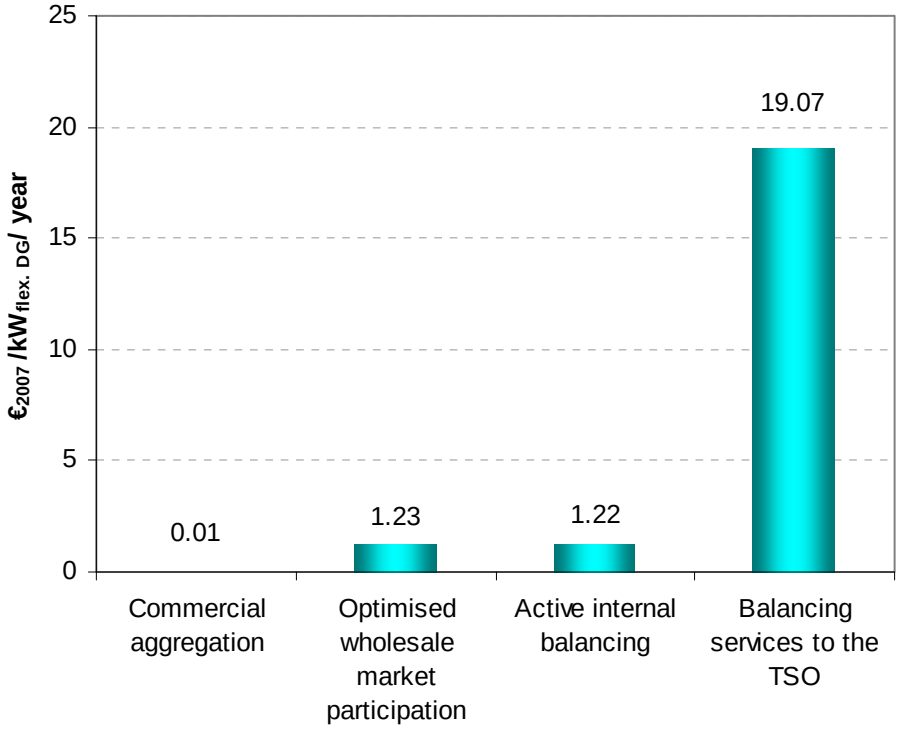

Figure 3.12 *System benefits in the SS for the different cases (future): cases Commercial aggregation, Optimised wholesale market participation, Active internal balancing, and Balancing for the TSO respectively*

Active internal balancing

Compared to today's situation, in the future more internal balancing will be provided by CHP units as imbalance costs will be higher. Like in 2007, the benefits of internal balancing are still lower than investment costs; nevertheless case 4 is almost neutral for the system.

Balancing services to the TSO

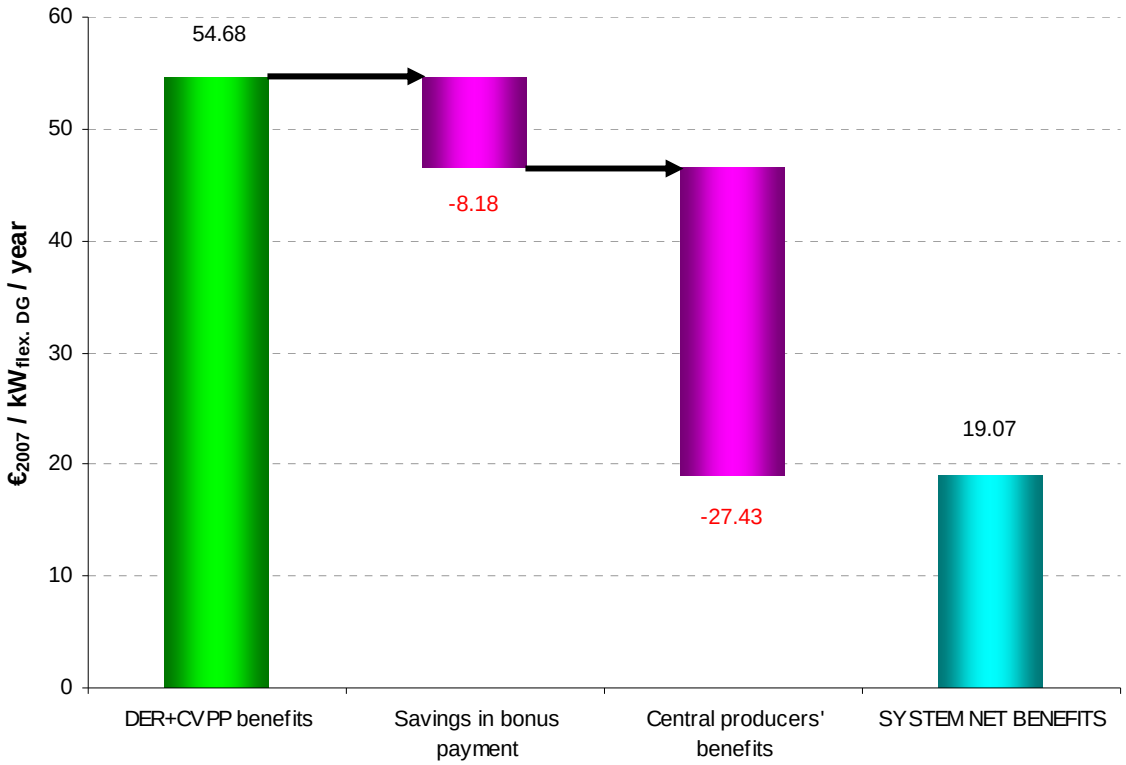

Figure 3.13 *Southern Scenario: net value creation by FENIX application balancing services to the TSO, in addition to active internal balancing and optimised wholesale market participation, for stakeholders and the electricity system as indicated by simulations at small-scale level, year 202**0***

From Figure 3.13 and the original data the following can be inferred. Benefits to be shared between DER and the CVPP are the highest in *Balancing services to the TSO*. In this case the benefits to be shared between DER and the CVPP will more than double up to € 54.68 for each flexible kW of DER included in the portfolio, compared to the current situation.

As in the case for today, the most beneficial case for CHP unit owners will be case *Balancing for the TSO* (see Figure 3.14). Yet for RES unit owners the cases *Balancing services to the TSO* case and *Active internal balancing* will be equally attractive (see Figure 3.15).

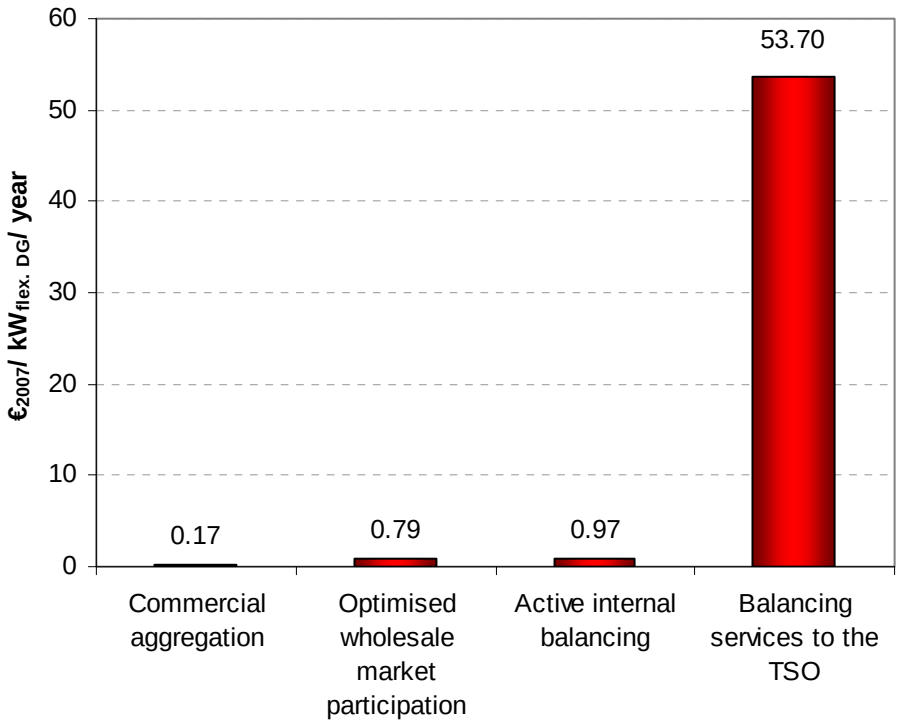

Figure 3.14 *Southern scenario: net benefits for CHP units, future*

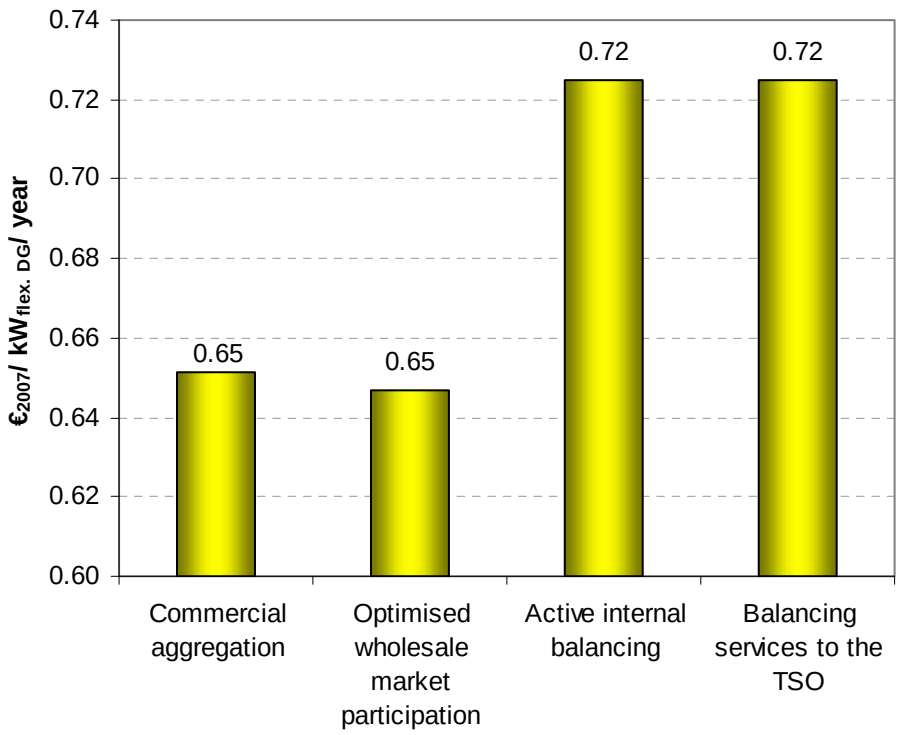

Figure 3.15 *Southern scenario: net benefits for RES units, future*

Contrary to today's case, *savings in bonus payments* decrease in the future. In the future DER units will be providing more upward than downward balancing, implying they will produce more

electricity and more money will be spent on bonuses. This concerns mainly bonuses for small-scale CHP units since bonuses will be removed for RES as well as large and medium size CHP units. However, as the use of DER is more efficient that traditional generation, the system as a whole is still able to save money.

DER units will keep on replacing *Central producers* in providing balancing services, so the latter will not be earning as much as in the reference case. All in all, *net system revenues increase by € 19.07 per flexible kW of DER*. Through regulatory interventions consumers stand to share in these benefits as well.

3.3.3 Upscaling

Northern Scenario

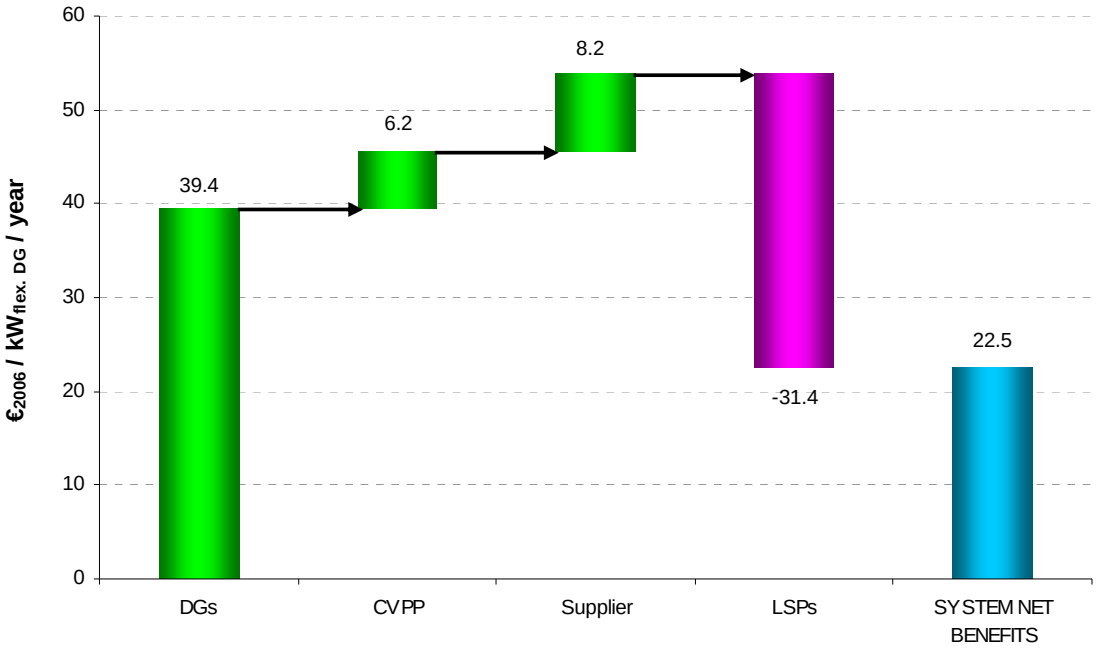

Figure 3.16 *Northern Scenario: net value creation by FENIX application optimised wholesale market participation for stakeholders and the electricity system as indicated by large-scale simulations for the year 2020*

System
Figure 3.16 shows that FENIX flexibility again delivers higher net revenues compared to the business-as-usual development of the reference case. The results from the upscaling of case study simulations for 2020 to the national level are fully in line with the case study simulations for 2020. A marginal decrease in the net benefits is visible due to the assumed price drop of 1%, decreasing the DG profitability only marginally.

Since the price effects of upscaled DG supply in the balancing market (i.e. case *Balancing services to the TSO*) are expected to be considerable given the limited size of the balancing market, it was decided to perform the upscaling exercise for DG supply in the wholesale market. The production supply in the wholesale market is only marginal affected by the upscaled DG production capacity.

Although the FENIX concept can be applied to a wide range of technologies, both on the supply and side and demand side, these results are based on market-based aggregation of small-scale CHP on the basis of gas engines for three reasons. First, the Woking demonstration focuses

mainly on gas engines. Secondly, gas engines dispose more than other CHP and intermittent technologies of the required flexibility to harness the benefits of the FENIX concept. Thirdly, the small-size of gas engines makes aggregation more valuable than aggregation of larger scale production technologies.

Accordingly, based on data of BERR (2007, 2008) for 2006 and 2020, and assuming the share of reciprocal engines remains equal over time, we estimate the CHP capacity of gas-fired engines will sum up to 1,150 MW in 2020. This implies a multiplication factor of about 500 of the production capacity used in the small-scale 2020 cases, which is related to the Woking demonstration project.

Optimised wholesale market participation
Like in the case study simulations for 2006 and 2020 the net benefits for the *CHP generators* increase substantially compared to the reference case since the presence of thermal storage facility enables CVPPs to schedule CHP dispatch at half-hourly settlement periods with highest day-ahead prices.

Like in the case study simulations for 2020, the profits for *CVPPs* increase as well. Since CHPs produce at more profitable hours, the value created by export for delivery to the UK APX is quite significant. Average DA prices against which power is exported are higher than average DA prices for the whole year 2020. With the dramatic increase of power export to the day-ahead market at the expense of conventional large-scale producers, CVPPs gain higher handling fees from operators of flexible CHP plants. These handling fees are further increased by the additional margin in this FENIX case, since the CVPPs not only aggregate financially but also operationally. The higher handling fee more than compensates for SCADA costs to enable operational aggregation. Handling fees from load diminish since more power has to be imported from the suppliers, which costs are higher compared to costs of imports of CHPs. Consequently, the profit margin for delivering power to loads decreases.

The net benefits for *Suppliers* increase like in 2006 and 2020. This increase results mainly from higher handling fees due to the increase of power exports of CVPPs.

As expected, the net revenues of the *large scale generators* decrease. Again, in the hours with higher DA prices electricity originating from large-scale generation is replaced by electricity from small-scale distributed generation.

Southern Scenario

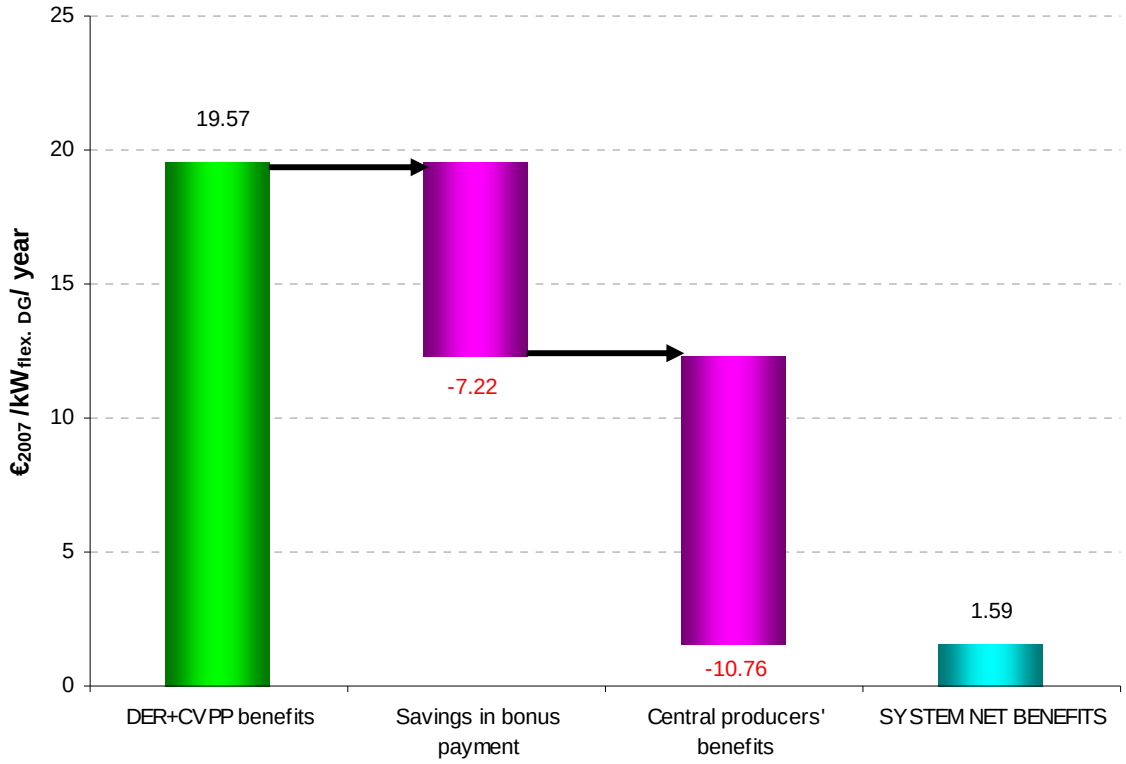

Figure 3.17 *Southern Scenario: net value creation by FENIX application balancing services to the TSO, in addition to active internal balancing and optimised wholesale market participation, for stakeholders and the electricity system as indicated by large-scale simulations for the year 2020*

System
Figure 3.17 indicates that system savings per $kW_{flexible\ DG}$ for the situation of FENIX management of an upscaled DER portfolio in 2020 are considerable lower than for the small-scale demonstration projects today (2007) and in the future. This results mainly from the relatively small size of the balancing market, limiting the possibilities for provision of this most profitable service for DER units. The system savings are again entirely due to the increase of DER+CVPP benefits compared to a situation without FENIX. This increase more than compensates for the decrease of savings in bonus payments and central producers' benefits.

Balancing services to the TSO
As in the conditions with a small penetration of FENIX, the most beneficial case for CHP unit owners would be *Balancing services to the TSO*. Both *Active internal balancing* and *Balancing services to the TSO* would be equally attractive for RES unit owners. With a widespread implementation of FENIX, however, DER units would not be earning as much money as they would do with a small penetration, as different DER units included in FENIX would be competing with each other. This would especially affect the profitability of CHP units, as each of them would be able to provide less balancing.

Benefits to be shared between DER and the CVPP would be the highest in case *Balancing services to the TSO*. The benefits to be shared between DER and the CVPP would be € 19.57 per kW of flexible DG. Compared to the small-scale simulations of FENIX applications in 2020, more money would be spent on bonuses and DER units would keep on replacing central producers in providing balancing services. Consequently, central producers will be inclined to decommission old, inefficient power plants. Furthermore, since central producers earn less money

from the provision of services than in the reference case, they will probably lower investments in new power plants.

3.4 Benefits for the investors

For the take-off of FENIX, it is of paramount importance that FENIX creates additional value (net benefits) to the stakeholders that have to invest in the net benefits of embracing the FENIX concept, i.e. DER owners and the CVPP.[5] Where applicable, the direct partners of investors in FENIX should be included as well. Through enabling mutual contracts, the latter should not (more than) fully absorb, but acceptably share in the net benefits of FENIX as a pre-condition for making the application of FENIX happen. Whether a positive aggregate result translates into additional value for each of the implementing stakeholders depends on the mutual contractual relationship they enter into. As it is key that there is a 'FENIX pie' to share indeed, here we focus on the aggregate result. Hence, we zoom in on the aggregate investor perspective or, more broadly, the perspective of direct business stakeholders that stand to gain from successful FENIX applications.

In the Northern Scenario the key market participants for using FENIX are:

(i) DER, that is, owners/operators of the flexible CHP plants at Woking that contractually relinquish operational control of their plants to the CVPP

(ii) CVPP, that is, the CVPP operator of Woking controlling the aforementioned flexible DER

(iii) The Supplier, which is EDFE, the supplier who has a delivery-procurement contract with the aforementioned CVPP which includes charges for using the network of the DSO with which the Woking non-public micro network interfaces.

Figure 3.19 gives - for the Northern Scenario - a summary overview of the aggregate net value creation for the key FENIX investors/enablers of the distinct alternative cases (in brief: cases) with respect to the Reference case. The net value is expressed in money of the day per unit of flexible DG (CHP) under control of the CVPP, that is: $€_{2006}$ / $kW_{flexible\ DG}$ / year. This way of dimensioning the result makes readily possible to compare the outcome with a typical initial investment financing requirement in flexible DG for different plant sizes. The gas engines in the case of Woking would require roughly some 600 $€_{2006}$ / $kW_{flexible\ DG}$. Furthermore, analysis results are depicted for:

- Today's situation (base year 2006 in the Northern Scenario) in Woking;
- the situation in year 2020 in Woking; and
- for Case 1, the situation in 2020 when upscaling of the FENIX application in question to UK level[6] is considered.

The overall picture which emerges from Figure 3.18 is that[7] the main reason behind this small reduction is increased competition, also between DER (CVPPs), at settlement periods with high electricity prices. As said, in the next section we will explain the results per stakeholder in more detail.

As already explained, in the Southern Scenario all subsequent cases are incremental. All subsequent cases, i.e. *Commercial aggregation*, *Optimised wholesale market participation*, *Active internal balancing*, and *Balancing services to the TSO* are indicated to add value Today and in the future. When each case is considered separately, for investors in FENIX the most value by far is created in the Southern Scenario by the application *Balancing services to the TSO* (see

[5] In our simulations it is assumed that the CVPP will invest in FENIX ICT. This does not necessarily imply that the (C)VPP owner has to do so indeed. This depends on the priority government authorities attach to a fast roll-out of FENIX applications and consequential evolving legislation. In fact, in order to kick start market deployment of FENIX initial socialization of DG metering equipment or other incentives might be considered.

[6] Except for Northern Ireland.

[7] Because of modelling complexity the upscaling simulations have been performed in the Northern Scenario for FENIX application wholesale market access for flexible DG only.

Figure 3.19). Like in the Northern Scenario in the Southern Scenario, upscaling in the future will reduce the value creation per kW flexible DG. This impact is more pronounced in the Southern Scenario where the relatively large industrial CHP units greatly increase the competition on the market for balancing services to the TSO. Considered in isolation, in the Northern Scenario the application *Optimised wholesale market participation* is the largest FENIX cash cow. As the wholesale market is much larger than the TSO-organised market for balancing services, the profit-dampening effect of upscaling is relatively smaller in the Northern Scenario than in the Southern Scenario. Even so, also with upscaling, the FENIX concept brings in handsome returns for investors, today and in the future in both Northern and Southern Scenarios.

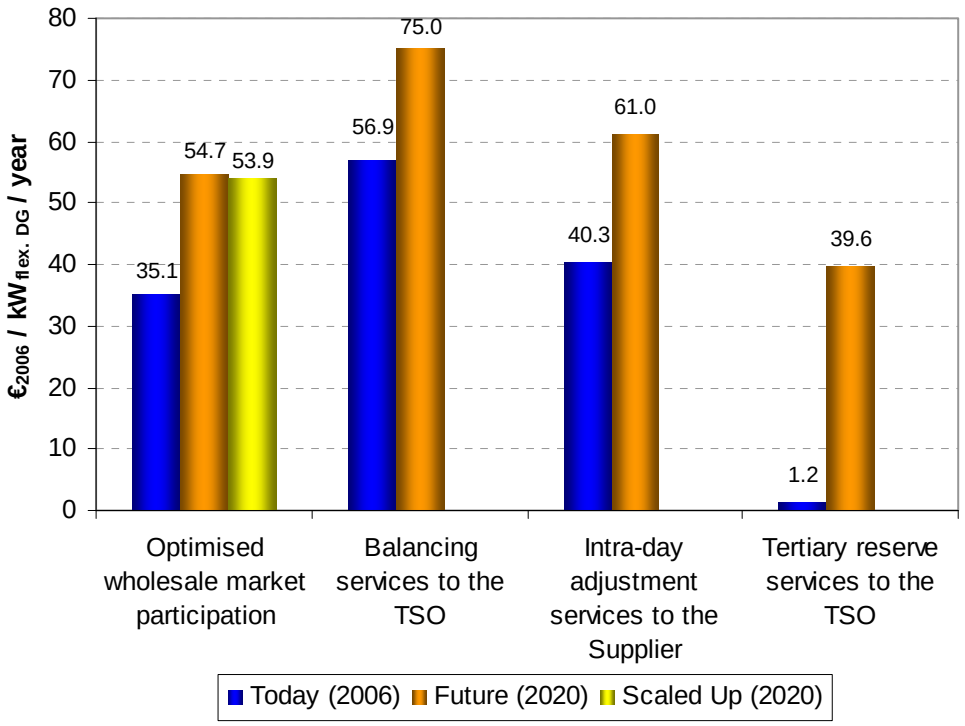

Figure 3.18 *Value creation in alternative cases of the FENIX concept in the Northern Scenario at small-scale level Today (base year 2006) and in the future for both small-scale level and upscaling (year 2020*

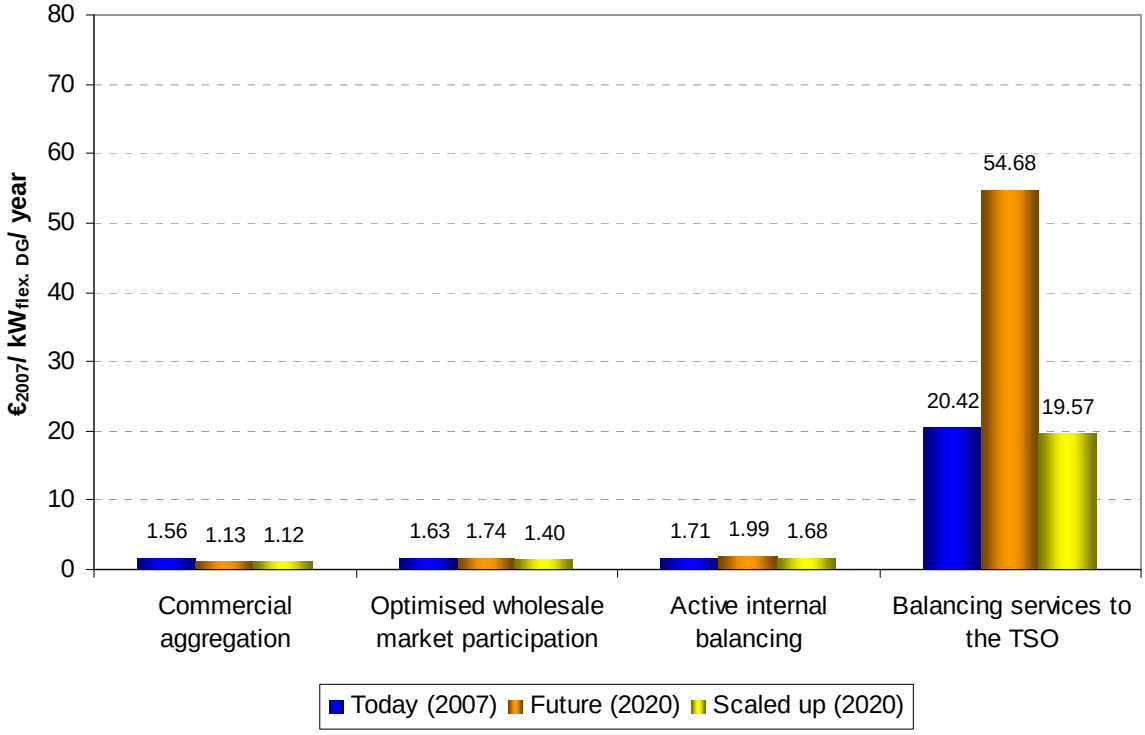

Figure 3.19 *Value creation in alternative cases of the FENIX concept in the Southern Scenario at small-scale level Today (base year 2006) and in the future for both small-scale level and upscaling (year 2020*

3.5 Socio-economic analysis

Northern Scenario

The more efficient deployment of CHP units guided by FENIX intelligence results in a higher overall system efficiency. Improved flexibility in the electricity system enables integration of electricity production from intermittent renewable sources (wind, solar) or less controllable sources like heat-led CHP units at lower costs. Overall, more efficient CHP units replace less efficient production technologies and vice versa for instance during periods when heat demand is lacking. This tends to result both in lower gas consumption and lower CO_2 emissions. Besides, the entry of flexibly operated CHP units in several markets contributes to competitive markets.

The additional value that FENIX creates in the electricity system has been evidenced by results of the cost-benefit analysis for an economy-wide deployment of FENIX in 2020. The adoption of FENIX results in reduction of system gas consumption by 37.5 MWh/ $kW_{flexible\ DG}$/ year in the case optimised wholesale market participation of flexible DG. This has favourable impacts on both security of gas supply and on CO_2 reduction. Compared to the reference case CO_2 emissions in the electricity sector are reduced on account of the adoption of FENIX by 7.5 kg $CO_2/kW_{flexible\ DG}$/year. Finally, also a better functioning of wholesale and balancing markets may be expected due to the entry of additional DG to these markets.

Southern Scenario

The more efficient deployment of CHP units guided by FENIX intelligence results in a higher overall system efficiency. In the Southern scenario, this efficiency mainly results from the operation of CHP units in the balancing market. When the system operator requests upward balancing, CHP units replace less efficient central power plants production technologies, while when

downward balancing is requested CHP units replace more efficient CCGTs and hydro plants, to the benefit of system efficiency. This tends to result both in lower gas consumption and lower CO_2 emissions. Besides, the entry of flexibly operated CHP units in several markets contributes to competitive markets and lower prices for consumers. If FENIX will be adopted in the future (2020) economy-wide, fuel savings in the Southern Scenario reach about 65 GWh of natural gas/ $kW_{flexible\ DG}$/ year in the case balancing services to the TSO. Hence in the Southern Scenario benefits regarding security of gas supply and reduction of CO_2 emissions can be realised by adoption of FENIX. Compared to the reference case CO_2 emissions in the electricity system are reduced by 13 kg $CO_2/kW_{flexible\ DG}$/ year. The difference between Northern and Southern scenario gas consumption and CO_2 emission reductions is partly due to differences in assumptions regarding the portfolio of displaced conventional generators and their pertinent fuel conversion efficiencies. Finally, also in the Southern scenario efficiency gains from better functioning wholesale and balancing markets are expected when additional DG enters these markets.

4. USING FENIX IN DISTRIBUTION SYSTEMS MANAGEMENT: A QUALITATIVE ASSESSMENT

4.1 Introduction

The cost-benefit analyses in the preceding chapters have not captured *quantitatively* the economic value that use of DER flexibility may have for delivering network management services the DSO. This would imply involvement of another system actor, notably the technical VPP (TVPP). The TVPP has the function of characterising the operating parameters of DER in a particular network location; it aggregates local network and DER capabilities to provide a picture of the capabilities of the distribution network at its interface with transmission. Simulation of the delivery of network management services by the TVPP is very complex and location-specific. For a specific situation it requires among others (sweeping) assumptions regarding network planning methodology, demand (annual total and distribution over time), demand growth, demand and DG localisation, DER growth and localisation. Results obtained for one specific situation can not be generalised as each situation is in a different topological setting. This chapter analyses in a more qualitative fashion the benefits of application of the FENIX concept to distribution system management.

Main findings from the qualitative analysis of existing literature are that application of the FENIX concept to the provision of ancillary distribution network services to the DSO by virtue of operational control over flexible DER by FENIX TVPP intelligence can mitigate the - at medium and high DG penetration rates rising - network costs through:

- Reduction of network energy losses (at low/medium DG penetration rates).
- Deferral of network investments.
- Reduction of penalties: both for non-supplied energy and for loss of quality of service.
- Enlarged scope of options for foremost distribution but also transmission network operators to integrate DER into active management of their respective networks.

Moreover, rising penetration of variable renewable generation poses great challenges to reliability of electricity supply. A notable external effect for distribution network management applications under such circumstances is that adoption of FENIX can significantly enhance security of electricity supply with due regard for quality aspects.

Crucial in this is adoption by DSOs of the new network management paradigm, called active network management, in which DSOs dare to rely on network operational support by flexible DER. Enabling regulatory and contractual frameworks are to help this make possible.

4.2 Benefits of FENIX for network management

Qualitative analysis undertaken in FENIX Work Packages 1 and 2 and related studies suggests that, contingent on local network conditions, TVPP operations can reduce network costs through

- Reduction of network energy losses,
- Deferral of network investments,
- Reduction of penalties for both non-supplied energy and loss of quality of service,
- Enlarged scope of options for foremost distribution but also transmission network operators to integrate DER into active management of their respective networks.

Crucial in this is that the DSO engages in active network management. Then, by way of operational control of DER through (T)VPP intelligence, the DSO can integrate DER in such a way

that the latter can contribute to the DSO's management of active and reactive power flows within his network.

In order to gain some insight into the net benefits of applying the FENIX concept to network management, let us briefly outline some general findings transpiring from two other EU-supported research projects in this regard. The DG-GRID project investigated the impact of penetration of Distributed Generation (DG) in LV/MV distribution networks on regulated profits of distribution system operators (DSO) in the UK and Finland. Figure 4.1 shows typical results for the UK. The bars denote the estimated impact on net profits for DSOs in percentage points excluding the potential benefits of deferred network reinforcements; the hyphens include the latter benefits. The graph indicates a negligible to fairly large positive impact of DG at lower levels (up to 23% relative to network peak load) of DG penetration. In only one case shown at lower penetration levels (urban network; intermittent DG; high concentration; 23% DG penetration) a negative DG impact is indicated. In contrast, at higher levels of DG penetration (48%; 81%) negative impacts are dominant. Furthermore, we note that inclusion of the potential benefits of deferred network investments – when non-negligible – tend to improve the impact picture somewhat without reversing the overall nature of the DG profit impact.

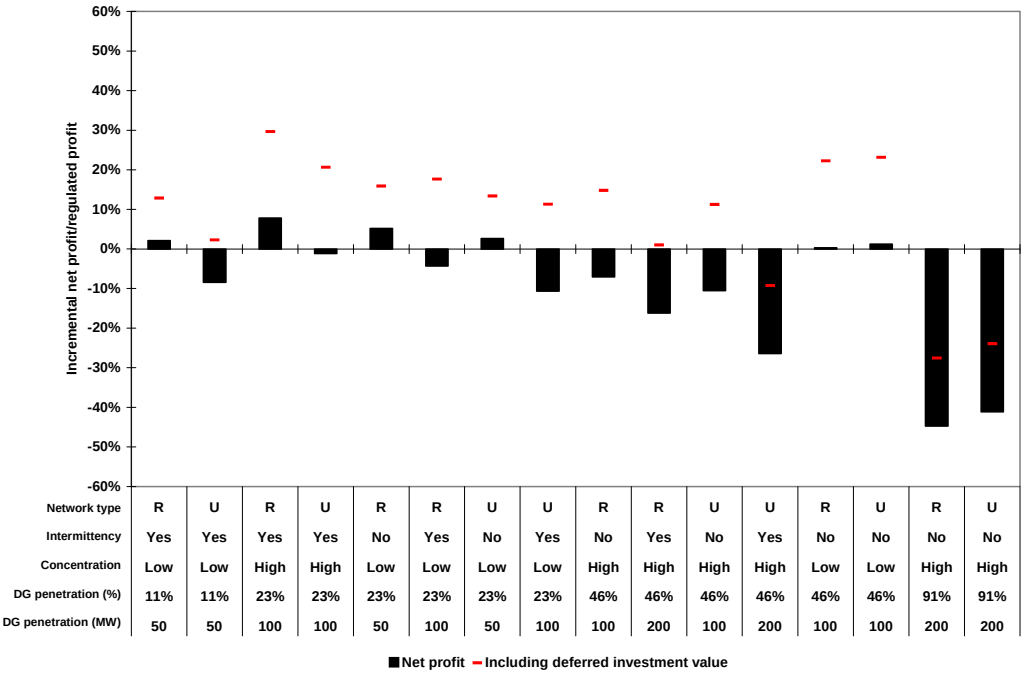

Figure 4.1 *Estimated impact of distributed generation on the regulated profits of DSOs in the UK under the network regulation framework prevailing in 2006 for selected typologies of distribution networks (source: DG-GRID)*

The ongoing IMPROGRES project has undertaken detailed case studies of selected existing network situations in the EU. Figure 4.2 shows a stylised representation of the relationship between increasing DG penetration and incremental network investment costs. It indicates less than proportionate incremental network investment costs at low levels of DG penetration turning into proportionate and subsequently more than proportionately increasing investment costs at rising levels of DG penetration. At high levels of DG penetration FENIX-mode intelligent, active network management is indispensable. Although, as we have noticed from the previous graph, adoption of the FENIX concept as such tends to reduce/defer network investments, it falls short of pre-empting the well-known economic "law of diminishing returns" to increased deployment of DG altogether.

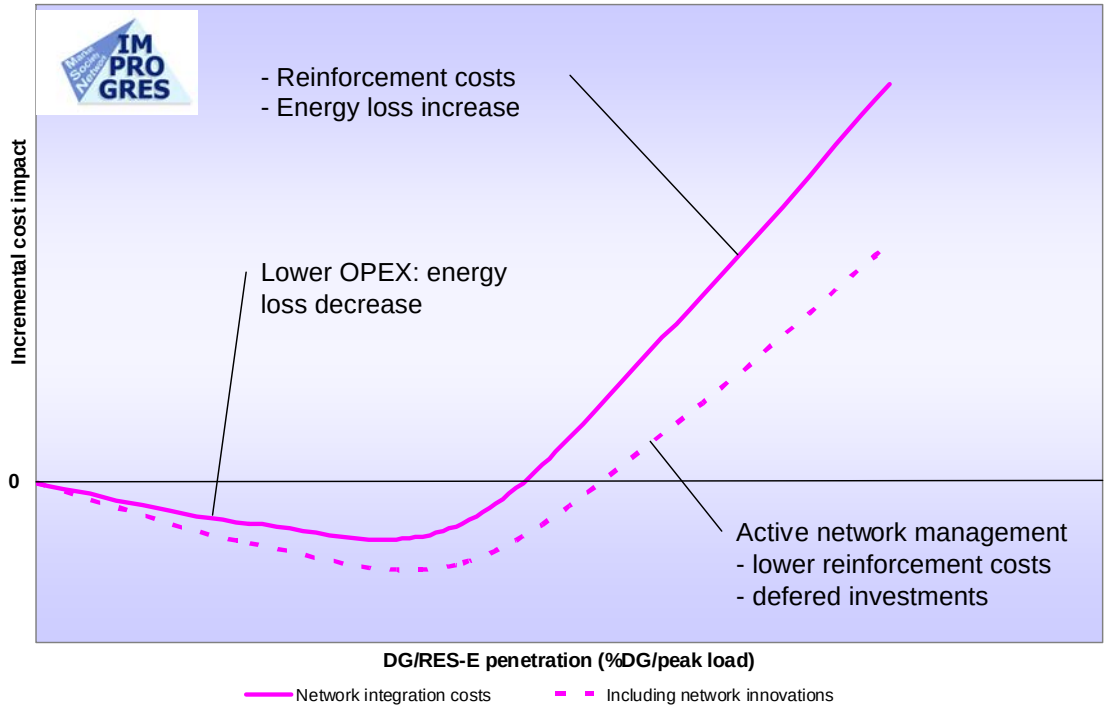

Figure 4.2 *Stylised representation of the relationship between total incremental network investment costs as a function of the penetration of distributed generation in a distribution network and the role of active network management in lowering these costs (Source: IMPROGRES)*

4.3 Key messages

Quantification of incremental net benefits on reduced/deferred investments in network reinforcement is extremely complex and very location-specific. In this chapter we have opted for a qualitative assessment drawing on results of two other EU-funded projects.

Results from two other EU-supported research projects indicate that applying the FENIX concept to distribution network management generates significant potential net benefits in terms of reduced/deferred investments in network reinforcement. Yet at the higher DG penetration ranges, the more than proportional investment cost rises as a result of increasing DG penetration will outweigh the benefits of FENIX. Hence especially in networks with increasing DER penetration FENIX can deliver substantial benefits for network management, thereby enhancing reliability and quality of electricity supply. FENIX can mitigate rising network costs that are poised to occur anyhow at high DER penetration levels.

For DSOs to embrace FENIX an enabling regulatory framework is essential. Some key features of such a framework are the following ones. The regulator should allow DSOs to include the necessary additional cost of integrating distributed generation into their service rates. In determining allowable rates the regulator should not introduce a bias in favour of recognising capital costs as against operating network costs and the other way around. Furthermore, DER support mechanisms should be designed such that these mechanisms do not impede their flexible network integration. FENIX deliverable D3.2.5 (Elis et al., 2008) and related studies such as (Scheepers et al., 2007) and (Jansen et al., 2006) provide more details on enabling regulatory frameworks.

5. CONCLUSIONS AND RECOMMENDATIONS

The more efficient deployment of flexible CHP units under guidance from FENIX IT intelligence results in (modestly) higher overall system efficiency. Improved flexibility in the electricity system enables integration of electricity production from intermittent renewable sources (wind, solar) at lower costs. Overall, more efficient CHP units tend to replace less efficient production technologies and vice versa for instance during periods when heat demand is lacking. This tends to result both in lower gas consumption and lower CO_2 emissions. Besides, the entry of flexibly operated CHP units in several markets contributes to competitive markets.

The additional value that FENIX creates in the electricity system has been evidenced by results of cost-benefit analysis for both scenarios, under the conditions for today and in the future, at small-scale level and with economy-wide penetration of FENIX. Investors in the FENIX concept and closely related stakeholders in the electricity stand to gain attractive returns.

In the Northern Scenario the adoption of FENIX results in reduction of system gas consumption. Large-scale use of the FENIX concept brings several benefits to the society. Fuel consumption decreases with respect to the reference case by 37.5 MWh/ $kW_{flexible\ DG}$/ year (case: *Optimised wholesale market participation of flexible DG*; economy-wide deployment in year 2020). This has favourable impacts on both security of gas supply and on CO_2 reduction. Compared to the reference case CO_2 emissions in the electricity sector are reduced on account of the adoption of FENIX by 7.5 kg CO_2/ $kW_{flexible\ DG}$/ year.

As for the Southern Scenario, if FENIX will be adopted in the future economy-wide, gas consumption can be reduced by 65 MWh/ $kW_{flexible}$ DG / year (case: *Balancing services to the TSO*; economy-wide deployment in year 2020). Hence also in the Southern Scenario benefits regarding security of gas supply and reduction of CO_2 emissions can be realised by adoption of FENIX. Compared to the reference case CO_2 emissions in the electricity sector are reduced on account of the adoption of FENIX by 13 kg CO_2/ $kW_{flexible\ DG}$/ year.

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Appendix A Northern Scenario: main assumptions

A.1 Introduction

In this Annex the main assumptions used for the Northern Scenario CBA simulations are presented. Our CBA simulations are based on the current situation with regard to the existing non-public network in Woking Borough County that is linked up to EDF Energy's distribution network. It is described in detail by Aunedi et al (2008). We have performed the analyses with monetary values in GBP pounds with a constant purchasing power of base year 2006. In the main text, for reasons of comparability for a wider European readership all monetary values have been converted to euros of 2006 applying the exchange rate £1 = €1.3. Furthermore, it is remarked that much effort has been made to validate the assumptions made on their realism with experts among FENIX project partners with relevant in-depth knowledge on the local situation regarding the case studies. Unavoidably, assumptions on the situation in year 2020 are surrounded with uncertainty.

Section A.2 describes key assumptions used for the simulations under today's (base year 2006) conditions. Key assumptions used for year 2020 conditions for small-scale FENIX applications are set out in Section A.3. Assumptions regarding the upscaling to UK-wide level are explained in Section A.4.

A.2 Assumptions for today (base year 2006)

A.2.1 General assumptions for the reference case

Current relationship between Supplier and Woking Aggregator
To date, only financial aggregation of the study DER takes place: the private network of the DER is connected to EDF Energy's 11 kV network at 4 points of interconnection and monthly settlement of the bill for the total energy exchanges takes place at these four points together during the past month, based on contractual fixed time-of-day tariff windows. EDF Energy assumes all unbalance costs (and revenues) occasioned by the study DER. All required third-party ancillary services to the TSO and DSOs are delivered by large power generators, connected to the TSO operated high-voltage grid.

Import and export tariffs
Currently, the Woking system operates with a special agreement from the Energy Supplier, EDF Energy. EDF Energy buys excess power produced by the generation resources and top-up any deficit in supply when local generation cannot meet demand. Each month the aggregate net position of the Woking sites is calculated (i.e. Total power imported – total power exported) and Woking is charged or compensated accordingly. In order to be able to properly gauge the impact of flexible operation of DG, we have assumed for the reference case that the tariff basis for energy exchanges between Woking and EDF Energy are the ex post prices on the Day Ahead APX UK power exchange. It is expected that smart metering at the level of DG will enable the introduction of market-based pricing. Moreover, a reference case with the current listed tariffs would blur the economic impact of flexible DG operation, because of differences between current tariffs and DA prices.

Woking CHP assets
In the reference case the CHP facilities are assumed to be operated at full load during fixed (half) hours of the day, irrespective of the season. The Town Centre gas-fired units have certain flexibility in delivering heat throughout the day by way of a hot water buffer and some of the other CHP assets do also have limited complementary heat buffering capacity. Yet, generally CHPs in the UK are not employed with thermal store. Besides, assuming that all CHP assets have been dimensioned to serve maximum in-doors heat demand, 23 or 24 hours/day schedules suggest negligible flexibility. Therefore, we assume no flexible operation of CHP facilities in

the reference case. Planned yearly general overhaul is assumed to take place from 1 July until 14 August.

On top of the energy revenues obtained through intermediation of the Woking DER aggregator, CHP operators are assumed to be able to collect a LEC premium to the tune of 4.4 GBP/MWh. Although in practice the LEC (Climate Change Levy Exemption Credit) premium varies to some extent, we have assumed that it is a fixed production premium at the average value in year 2006.

Woking loads
As for Woking loads, we have constructed a Woking electricity demand profile using the following assumptions regarding the electricity use by the Town centre and Pool in the Park premises:

- Profiled electricity demand = Scheduled production + Imports – Exports.
- Imports minus exports are differentiated by season based on (Aunedi et al., 2008: Northern Scenario, Tables 5-2 and 5-3, Average Daily Import/Export) .
- For lack of data we disregard electricity demand elsewhere in the Woking micro grid system.
- Since PV production is not included in import/export figures of Aunedi et al. (2008), except for one 9.11 kWp unit, we excluded PV production from scheduled production.

Role of large TN-connected generators
It is assumed that all (changes in) notified energy exchanges between Woking and the EDF Energy network are matched by likewise (changes in) contracted energy exchanges between the EDF Energy distribution network and the transmission network operated by NGC. It is assumed that all power imported by Woking Aggregator is purchased on the UK APX power exchange. This means that the Supplier pays the DA price for the procurement of the power from large scale generators (and, conversely, large scale generators receives the DA price). Subsequently this power is sold to the Woking loads through intermediation of Woking Aggregator.

The marginal cost of the large scale producer is assumed to be 57 £/MWh during the day and 41.5 £/MWh at night (hours between 00:30 – 07:30)[8]. When, the DA price is lower than these assumed costs, the marginal cost of the large scale operator is set to be equal to the DA price, in order to account for additional costs that would occur from the start up/shut down of the power plants.

Imbalances
We have modelled imbalances[9] in the following way:

- Deviations from profiled Woking electricity demand: at random between -2.5% and +2.5%;
- Deviations from profiled Woking DG production before passing on balancing responsibility by Woking Aggregator to Woking DG: at random between -1% and +1% for CHP units
- It is assumed that - after Woking DG assume the consequent imbalance transfers because of their imbalance positions themselves – they assume a more conservative bidding strategy. This is due to the fact that the SBP price is generally considerably higher than the SSP price. It can be very costly if the CHPs are short of power and therefore we assume that through more prudent operations the forecast error for the CHPs decreases by 50% with respect to the previous bullet;
- Different categories of imbalances are sometimes correlated.[10]

[8] The day and night marginal cost values are based on the realized average and off-peak average wholesale power prices, which were around 74 and 54 €/MWh in 2006 (Ozdemir et al., 2008). It has been assumed that the marginal cost of the marginal unit of the large scale generator follows the same trend.
[9] Imbalances refer to the amounts of energy generated or consumed and not covered by contracts (Exelon, undated)
[10] The portfolio effect is automatically taken into account, due to the construction of separate half-hourly imbalances from different generation sources, which sometimes offset each other.

Imbalance Settlement
Actual quantities of electricity produced and consumed are metered in real time. Any imbalance between market participants' contractual positions at Gate Closure, adjusted to include any accepted offers and bids and actual production/consumption is then determined. Imbalance volumes are settled at one of the dual imbalance prices; System Buy Price (SBP) and System Sell Price (SSP).

Two kind of situations can be distinguished:
- if a Balancing Mechanism participant is short in any period, he will pay the SBP;
- if a Balancing Mechanism participant is long in any period, he will receive the SSP.[11]

Imbalances *in the same direction* as the Transmission Grid are settled at the Energy Imbalance

Price calculated from National Grid's balancing actions. Usually, when there are no default situations:
- BM participants that are long when the system is long get paid the SSP, derived from National Grid's balancing actions. When the system is long, the SSP tends to be lower than the energy price on the UK APX; and
- BM participants that are short when the system is short pay the SBP, derived from National Grid's balancing actions. When the system is short, the SBP tends to be higher than the energy price on the UK APX.

Imbalances *in opposite direction* tend to be settled at a market price based on UK APX trade prices, when there are no default situations. When the system is long, the SBP is set on the basis of trade prices on the UK APX. When the system is short the SSP is also set on the basis of trade prices on the UK APX.

Use of Distribution System Charges
We have disregarded use of system charges to simplify the analysis. The relative amounts concerned are rather small and their incremental impacts even almost negligible, whilst the analysis will be significantly complicated by inclusion of Use of Distribution System Charges.

A.2.2 General assumptions: FENIX applications

Implementation of FENIX intelligence
Regarding the implementation of the Woking SCADA system the following assumptions have been made:
- Investment: 10,000 GBP.
- Projected economic life time: 10 years.
- Real weighted average cost of capital: 12%.
- Recurrent cost: 500 GBP/year.

This boils down to a levelised cost of GBP 2270 / year.

Implementation of heat storage
The following assumptions have been made:
- Investment: 100,000 GBP.
- Projected economic life time: 15 years.
- Real weighted average costs of capital: 12%.

This means a levelised cost of GBP 11300 / year.

[11] In some extreme situations (for instance, a lot more wind production than expected at a time when for conventional generators it is very costly to down regulate), the weighted average price of all accepted bids may become negative and consequently the SSP will be negative also.

Woking CHP assets

The units that have non-negligible flexibility of intra-day shifts are the gas-fired units of 2428 kW_e in the Town Centre and Pool in the Park[12]. All Northern Scenario case studies focus on the operational flexibility of these very units.

In the reference case the CHP facilities are operated at full load during fixed hours of the day, irrespective of the season. For the FENIX Cases, we assume that Woking CVPP optimizes the operation of the CHP units over and above arranging all transactions on behalf of Woking DG and loads. The relevant Woking CHP units are facilitated with both thermal storage facilities and back-up boilers[13]. Local heat demand will have to be fulfilled at all times, either through the CHP, thermal store or back-up boilers, whichever mode is most remunerative to Woking CVPP and flexible Woking CHP units. Therefore the business-economic decision for the Woking CVPP is either:

1. To run the flexible CHP units at maximum electric output. The heat, produced simultaneously, is delivered to meet the requirements of Woking heat loads while any excess heat is stored, or

2. To import electricity from EDF to meet Woking power demand and either discharge the heat storage facilities to supply local heat loads or, when there is not enough heat stored, to operate the boiler to meet local heat demand. Evidently, when there is enough heat stored to meet local demand, it is more economic to discharge the storage facility than operate the back-up boilers.

Partial loading of the CHP units was also considered as an option. However, since the CHP generators are price takers (their size is too small compared to the size of the market and therefore they cannot influence the electricity prices), *maximization of their profits will occur when they operate at full load whenever operating is profitable*[14]. Whenever operating the flexible CHP unit results in negative net revenues, the CVPP decides to switch them off.

In order to optimize the CHP operation we have assumed that the heat load curve given in Table A.1, below, applies. We only consider one active operational state for the electricity driven CHP plants. This is the maximum electric output, approximately 2.4 MW in total for all flexible CHP plants, and also maximum fuel efficiency for the CHP plants as a whole. We have assumed that this operational state corresponds to 2.8 MW of thermal output[15].[16] It is also assumed that any excess heat can be stored in the storage facilities, up to 7.5 MWh, which corre-

[12] The fuel cell in the Pool in the Park complex is excluded from the optimization because it is characterized by negligible flexibility. Furthermore, the ramping constraints have been relaxed for the Jenbacher unit for simplification.

[13] The existing back-up boilers seem to be relatively inefficient (e.g. the efficiency of the Pool in the park back-up boiler is only 60%). In order for the optimization exercise to be more meaningful, we have assumed that the efficiency of the back-up boilers is 90%.

[14] If the CHP is making profit by producing one unit of electrical output, then it will maximize its profits by maximizing its output, since we assume constant marginal production cost. There is a case that the latter is not true; when part of the heat produced is damped. For the power production that corresponds to the useful heat part, the marginal cost should be calculated taking into account avoided fuel costs, while for the rest avoided costs should not be considered. Even in this case though, the operational options are discrete and 3 in particular; switched-off, when MC of CHP and non-CHP part is higher than DA price, or partially loaded at capacity of CHP-part (i.e. capacity that corresponds to useful heat output), when MC of CHP part is lower than market price but MC of non-CHP part is higher, or operating at its nominal capacity, when MC of non-CHP part is lower than market price. For simplicity, part-loading is not considered as an option.

[15] For the calculation of the electric and thermal output of the aggregated CHP unit, a maximum electric and thermal efficiency of 40% and 46% respectively was assumed. These values are the average of the actual efficiencies of the CHP units at Town Centre and Pool in the Park.

[16] In reality, the electrical and thermal output of the CHP units might vary throughout the year so that the units still comply with the regulation for the issuing of LECs For example the demand for heat is expected to be considerably lower in the summer; this might limit the maximum electrical output of the CHP plant depending on the type of the CHP, e.g. if its type is of constant P/Q.

sponds to the capacity of the thermal store[17]. Heat losses (equal to 0.2% per settlement period or approximately 10% per day) and efficiency for the charging/discharging cycle (85% efficiency is assumed for the full cycle) are also included in the optimization algorithm.

Table A.1 *Woking Heat Demand*[18]

Period	Heat Demand [MW_{th}]
1	0.3
2	0.7
3	1
4	1
5	0.7
6	0.3

FENIX application: Optimised wholesale market participation of flexible DG

In this application we optimised the combined operation of the CHP-storage-boiler facilities, assuming that the Woking DGs are participating in the DA market, i.e. their production is sold for the DA prices. Naturally, the Woking DGs are very small compared to the size of the market and therefore they are price-takers. This implies that the decision to be taken by the CVPP is whether the CHPs will operate in a settlement period or shut down. If it is profitable for the DGs to operate, then they will maximize their profit when maximizing their output. The two options are described below.

1st Option: Operate CHP to provide electricity and heat.

The first option to be considered is when the CVPP decides to operate the CHP at its maximum electrical output. Then the revenues for the DGs[19] would be:

$$Net\,\mathrm{Re}venues(1) = Qe,\max \cdot (Pe + LECs) + Qth \cdot Pheat - {Qe,\max}/{ne} \cdot Pfuel$$

, where

Qe,max stands for the maximum electricity output,

Pe represents the DA price of electricity,

Qth the local heat demand,

$Pheat$ the heat price,

ne the electrical efficiency of the CHP (it is assumed that the CHP is operating at its maximum efficiency), and

$Pfuel$ the price of the fuel the CHP is using.

It should be noted here that we have assumed that the CHPs are always operating at maximum electric output (according to Aunedi et al. the operation of the Woking CHPs is electricity driven and hence this seems a logical assumption). Furthermore, their electric and thermal output is connected to the efficiency of the plant which is assumed to be the maximum technically feasible (i.e. maximum electric and thermal efficiency) [20]. Generally there are two counter factors when deciding the operating efficiency of the plant; the efficiency must be above 70% in order

[17] For the calculation of the thermal store's capacity, a temperature difference of 25°C is assumed between heat stored and heat delivered. The volume of the thermal store is 260 kL of water as described in Aunedi et al (2008).

[18] The periods in the table coincide with the periods as defined in the contract with EDF.

[19] The two CHP units have been considered as one aggregated unit for simplification and because their characteristics are very similar, which implies that such an assumption does not deviate significantly from reality.

[20] In economic terms this is also the optimal operation.

for the CHP to qualify for Levy exemption certificates (LECs), but at the same time the amount of heat to be dumped should not exceed a certain level determined by the authorities.

The thermal output in this case could be more than the demanded heat. When this happens, the additional heat is stored. Hence, it can be used at a later stage for meeting heat demand.

2nd Option: Import electricity, discharge heat from the storage facility or operate the boiler to produce heat

In this case, the Woking CVPP imports electricity from the supplier to meet local power demand and either discharge heat from the storage facility or, second-best, operates the boiler to meet local heat demand. Evidently, when there is sufficient heat stored, it is more economical to release this heat than operate the boiler. The revenues in this case are calculated as below:

$$Net\,\mathrm{Re}venues(2) = Qth \cdot Pheat - {}^{Qth}\!/_{nboil} \cdot Pfuel$$

, where the last factor is omitted when enough heat is already stored (and therefore it is optimal to discharge the thermal store).

The product $Qth \cdot Pheat$ is present in both formulas so we can ignore it[21]. The net revenues for the two options are calculated and the one that gives the higher revenues (higher revenues also mean lower losses) is chosen by the CVPP.

<u>*FENIX application: balancing services to the TSO*</u>

This case assumes that Woking CVPP controls deployment of DG in the following way:

1. As a first step, the CVPP optimizes the operation of the DERs in the DA market in accordance with the previous case, optimised wholesale market participation of flexible DG.

2. The first step also determines the type of balancing services Woking CVPP can offer to the TSO. If at gate closure, one hour before real time, the CHP plants concerned are scheduled to operate, they can provide downward regulation services and vice versa when they are scheduled in idle mode.[22] From Gate Closure, the Balancing Mechanism is operated by National Grid to clear the net imbalance of the system (and possible congestions). At Gate Closure every Balancing Mechanism Unit knows its intended operational status for the relevant Settlement Period and hence whether and to what extent they can provide upward or downward[23] balancing services.

After completion of trading on the day-ahead market, Woking CVPP prepares offers (willingness to increase generation) or bids (willingness to decrease generation) on behalf of DG under his control, depending on their intended operational status based on DA market contracts:

- In case DERs are not contracted via the day-ahead market to provide output, they can provide upward balancing services for this settlement period. We assume that the offer price will be equal to *the marginal cost plus start-stop cost (the cost for operators to ramp up and, after having delivered the service, to ramp down) plus a required profit mark-up*. To calculate this we assumed:
  - starting and stopping the CHP unit will decrease its life time; one start and stop is assumed to decrease the life time of the CHP unit by an hour

21 Moreover, we have no information about heat prices in Woking.

22 It is recalled, that the optimization process considers only two states for the CHP (as explained in more detail in the description of Optimised wholesale market participation of flexible DG): CHP on and running at its nominal capacity or CHP off.

23 Bids lower than the market clearance price (Spot or Day-Ahead price) are accepted and hence must be delivered, while bids higher than the DA price are rejected.

- investment costs of an average CHP unit are assumed to be 430 £/MW and 48,000 operating hours
- The offer price has to cover at least all associated costs as well as a "normal" profit mark-up for being profitable for DERs to provide this kind of balancing services. We assume a profit mark-up of 5 £/MWh
- DERs are remunerated for LECs in case they provide upward balancing services since LECs are provided for the actual production of the CHPs, whatever its application (compliance with DA market contract; response to call to provide upward balancing services).

- When DERs are contracted to provide output via day-ahead trading, they can provide downward balancing services for this settlement period. Since, a bid "*is effectively the offer of a negative volume*" (Elexon, undated) it corresponds to a negative cash flow, i.e. payment from the BM participant concerned, i.e. Woking CVPP, to the TSO. We assume that the bid price will be equal to: *the marginal cost minus the LEC premium minus the shut-down cost minus the required profit mark-up*. The shut-down cost are the cost of the DGs to ramp down and stop, and to start-up from warm conditions, set at half of start-stop costs i.e. 10 £/shut-down.

In latter case, the profit mark-up is subtracted from the MC of the DERs, because as explained above accepted bids correspond to payment to the TSO. LECs are also subtracted in this case, because it is assumed that the CHP generators concerned will qualify for LECs. Hence, if Woking CVPP's bid is accepted, it will provide downward balancing services (i.e. decrease generation). If the bid is accepted, the DERs will increase their profit compared to their original scheduling[24].

The acceptance of the offers/bids submitted by the CVPP will depend on the net position of the GB system and the other offers/bids submitted for the same settlement period. More specifically, whether these offers/bids will be accepted depends on the highest offer/lowest bid respectively, i.e. if lower than the highest offer, accepted, if higher than the lowest bid, again accepted.[25]

FENIX application: Intra-day balancing services to the Supplier

For designing this application, it is important to know whether the application can be assumed to be incremental to former cases or not. *Balancing offers and bids in the GB can be accepted by the TSO during a 90 minute window after Gate Closure (one hour before the start of the relevant Settlement Period) up to the end of the relevant Settlement Period.* Consequently, the operational status of DERs can change at any time in this 90 minute window and for the settlement period that the DERs have submitted offers/bids. Therefore at that time the CVPP is not able to choose between provision of balancing services to the TSO or the supplier. Furthermore, the CVPP is not able to provide balancing services to both the TSO and supplier concurrently (for the same MW), since offers and bids to the balancing market are binding and he will face non-delivery charges for not being able to deliver the already offered balancing services. Therefore, the CVPP must choose whether to provide balancing services to the supplier or to the TSO. Hence, the FENIX application Balancing services to the TSO cannot be considered as starting point for this application but denotes an alternative application to Woking CVPP, requiring the latter to make ex ante choices. Hence, the applications balancing services to the TSO and intra-day balancing services to the Supplier are mutually exclusive.

The supplier under study has a relatively low imbalance risk. This is not expected to be the typical case in the future, when high penetration of intermittent sources will result in greater imbalance variability. Hence, if this supplier is considered as the representative one this will clearly not be illustrative of a future as depicted by the FENIX Futures scenario and diminish the FENIX

[24] It is noted, that it is assumed that no strategic behavior by Woking CVPP is assumed. E.g., no hoarding reserve capacity is assumed to take place for the provision of upward balancing services at period of the day that ramp-up capacity is most required.

[25] This might not be totally correct as the acceptance of an offer/bid might be affected by other factors as well, e.g. time of submission or incidence of congestion. Yet, it seems to be a good approximation.

value beforehand. To account for the full value of FENIX concepts, we therefore simulated a Supplier's portfolio which includes a lot of intermittent renewables Consequently, the imbalance position of the Supplier is assumed to be in the relatively wide range of [-100 MW;100 MW].

Concerning the type of bilateral contract between Woking CVPP and the Supplier, there are two possibilities with respect to CHP availability. In practice, distributed CHP generators or their CVPPs do not appear to reserve any *firm* power for balancing market operation. Therefore, Optimised wholesale market participation of flexible DG is considered as a starting point and the availability of CVPP for balancing is *contingent* on this case. Besides, it is assumed that it is the prerogative of the Supplier to call Woking CVPP, whilst Woking CVPP is not allowed to offer alternative balancing services to the TSO for the duration of Woking CVPP's bilateral contract with the Supplier.

Considering the utilization of the Woking CVPP by the Supplier for the provision of balancing services by the former to the latter, the Supplier will demand upward balancing services from CVPP Woking, when the Supplier is short and the contract price between the two actors is lower than the expected SBP. Downward balancing services will be demanded by the Supplier, when the Supplier is long and the contacted payment to Woking CVPP is higher than the expected SSP. Since the SBP and SSP are only known after real time, expected SBP and SSP have to be estimated. These imbalance prices are roughly approximated by the most recent SBP and SSP prices when the system was short or long respectively.[26]

Woking CVPP is offered at least a minimum contract price based on Woking marginal costs + start-stop/shutdown costs. Moreover, when ex post the Supplier turns out to have net benefits on top of the minimum fee, 50% and 20% of these benefits are assumed to be passed on to Woking CVPP and subsequently to DGs, in the case of Supplier with high and low imbalance risk respectively[27]. As a sort of compensation for the prerogative of the Supplier to place mandatory calls for balancing services, the Supplier is supposed to bear the risk of net losses, when settling the contracted transactions at the minimum contract conditions from Woking CVPP's perspective.

In the current model set-up, at some settlement periods the Supplier is poised to make a loss. This occurs when actual SBP < contract price < expected SBP (actual SSP > contract price > expected SSP). Thus for example, if the Supplier decides to order upward balancing services from CVPP, because they expect SBP to be higher than the minimum contract price, but realized SBP is lower than that, then the Supplier will have net losses (pays – at hindsight - a higher price than he would have had to incur when purchasing balancing services straight away from the BM).

FENIX application: Tertiary reserve services to the TSO

From the available tertiary services in the UK system, one particular service has been selected for elaboration in FENIX context. We have analysed the available services and our conclusion is that the most suitable service for the Woking DGs is the Short-Term Operating Reserves (STOR) service. In fact, the size of the STOR market is the biggest from all other tertiary service markets.[28] The STOR service consists of two types of contract: *committed* and *flexible* contracts. Both BM and non-BM units can sign a committed contact, while only non-BM units are allowed to offer flexible service. These contracts are signed between the National Grid and the respective units in one of the 3 tenders that are organized by the National Grid in every financial year (i.e. from April to March of next year). Every year is divided into 6 seasons, not necessarily

[26] If the system state is not taken into account, estimated SBP may be too low (SBP = UK APX price) or SSP may be too high (SSP = UK APX price).

[27] It is assumed implicitly that a supplier with high imbalance risk is willing to award a higher share of the benefits to the DGs, because it has a greater incentive to balance its generation as close as possible to their scheduled output; high imbalance can result in significant losses.

[28] At this point, the authors would like to thank Ms Rebecca Young of NGC for the very constructive dialogue they had, the information offered and comments made, and Mr Simon Bradbury of Pöyry for the very helpful inputs on the elaboration of this FENIX application.

of the same duration. For every day within a season, 2 (or 3) windows[29] are defined, during which the National Grid requires availability of the contracted STOR units. Generally, these windows coincide with the periods of high demand (e.g. between 07:00 and 13:00).

According to the terms and conditions of a committed contract, the contracted unit is required to be available at all windows within the season(s) for which it has been contracted. On the other hand, a unit that has signed a flexible contract with the National Grid can opt for the provision of STOR services on a weekly basis, i.e. it can choose before the commencement of the relevant week whether it would like to offer STOR services for this particular week or not. In the case of a flexible contract the final decision belongs to the National Grid. Hence, if the National Grid has already met the STOR requirement, which has been predetermined by themselves in previous stages, then they would reject the offer by a 'flexible' unit and no payment will be made available to the latter for the relevant week.

Every contract is characterized by two payment elements; an availability and utilization payment, which are unique (pay-as-bid system). These two elements are part of the offer made by the unit and at the same time the basic criterion on which the National Grid decides whether to accept or reject an offer[30]. The availability payment, measured in £/MW/h, is made available to the contracted unit for all the hours that it reserved its contracted capacity, in order to provide STOR services to the TSO if needed. The utilization payment, measured in £/MWh, corresponds to the energy delivered by the contracted unit to the National Grid in the context of STOR. The two prices can differ from season to season but they remain constant within a season.

For the simulation purposes, it is assumed that the under study DGs are getting involved in a contract, of "committed" type, with the National Grid for the whole year. This reflects the fact that the majority of the required STOR capacity is offered via committed service. It is assumed that they offer their nominal capacity and that the availability and utilization prices are equal to the average availability and utilization prices of the accepted offers of tender 1 for the year 2007/08[31]; that is 6.21 £/MW/h and 228.41 £/MWh respectively (data retrieved from annual STOR report for year 2007/08).

We assume that Woking DG, controlled by Woking CVPP, are always available to provide reserves to the National Grid during the predefined STOR windows. In other words, the operational status of the DG is automatically set at "OFF" during the STOR windows (e.g. between hours 07:00 and 13:00, and hours 19:00 and 22:00 during the 1st season, which lasts from April 1st to April 28th). Only when, and for as long as instructed to provide output will their operational status change. *For the time of the day outside the STOR windows it is assumed that Woking DG participate in the Power Exchange and Balancing Mechanism markets*. It should be noted at this point that no distinction has been made between weekdays and non-weekdays with regard to STOR windows for modelling simplification. For all days the weekdays STOR windows are used (in reality, different windows are defined for weekdays and non-weekdays per season).

Regarding the utilization of the DGs for the provision of STOR, the average utilization per MW in 2007/08 was calculated at around 50 hours/year[32]. To take into account the different utilization rates that can occur from unit to unit, in our simulations we have assumed two aggregate active

[29] Generally, 2 windows are defined in a day, a morning and a night one. Only during these windows the contracted parties need to be available to the National Grid.

[30] The least-cost criterion has a key role in the decision taken by the National Grid. In addition, other criteria, such as respond times, or more generally, the technical characteristics of the tendered unit, or location of the unit, play a significant role in the decision by the National Grid.

[31] Basically, there is one reason for this selection; from the annual 2007/08 report it is apparent that the majority of the participating units offered their services in the 1st tender (more than 90% of the accepted new committed capacity for the whole year was signed in this tender). Analysing more tender periods would make the analysis more complex without increasing the robustness of the analysis significantly.

[32] Total STOR utilization for year 2007/08 was 116.2 GWh (including power delivered during optional windows) and the average total contracted STOR capacity for the 6 seasons was 2362 MW (both including committed and flexible service). That is equivalent to 49.1 hours of utilization per MW per year.

time levels, an utilization rate of 50 hours/year and an utilization rate of 80 hours/year respectively.[33] These values cover a range within which the actual utilization rates are likely to fall.

A.2.3 Contractual assumptions

Hereafter we explain key assumptions on contractual relationships that were not yet set out above.

Reference case

The relationship between Supplier and Woking Aggregator has been stylised as follows:

- Woking CVPP assumes balancing responsibility for Woking's net injections into / absorptions from the EDFE network
- For using distribution network services and covering administrative/metering costs, Woking CVPP pays EDFE for load absorptions the DA price plus 6% delivery charge
- For using distribution network services and covering administrative/metering costs, Woking CVPP receives from EDFE for load ejections into EDFE's network the DA price minus 6% handling charge.

On the relationship between Woking Aggregator and Woking electricity end-users we made the following assumptions:

- Woking loads pay Woking CVPP a tariff based on 110% of the DA price. This includes a handling surcharge for delivery of Woking intra-network services, metering and billing and – to the extent that the load is provided externally – a 6% delivery charge by EDFE
- Woking creates imbalance at the Supplier level, originating from both Woking loads and Woking DG. The imbalance created by Woking loads is assumed by the CVPP.

Assumptions used on the relationship between Woking Aggregator and Woking DGs are:

- In the Reference Case, when Woking CVPP is in fact just an aggregator of financial services, Woking CVPP pays Woking DG (100% - 6%) of the DA price minus an additional 3% margin: hence 94*97 / 1000 %. The 6% relates to the handling charge the CVPP has to pay to EDFE in case the Woking DG generation is evacuated to the EDFE network. In the case that internal Woking generation is absorbed by Woking load, the 6% margin factor enhances the margin for Woking CVPP.
- In the FENIX cases, when Woking CVPP acts both as an operational DG ('DER') aggregator as well as a DG aggregator of financial services, Woking CVPP pays Woking DG (100% - 6%) of the DA price minus an additional 5% margin: hence 94*95 / 1000 %. The 6% relates to the handling charge the CVPP has to pay to EDFE in case the Woking DG generation is evacuated to the EDFE network. In the case that internal Woking generation is absorbed by Woking load, the 6% margin factor enhances the margin for Woking CVPP
- Woking creates imbalance at the Supplier level, originating from both Woking loads and Woking DG. The imbalance created by Woking DG is assumed by the DG themselves. The Supplier passes on transfers with the TSO on account of Woking imbalances to Woking Aggregator, who in turn conducts transfers with the Supplier on account of imbalances created by Woking at large.

FENIX application: Optimised wholesale market participation of flexible DG

Assumptions on financial transfers between the Supplier and CVPP are:

Regarding the energy transfer prices the same assumptions as in the reference case are followed with regard to import and export prices:

- The import tariffs to be paid by Woking CVPP to EDF Energy are:
  - Woking CVPP pays EDF Energy CVPP the DA price for the half hour time block concerned plus a handling fee, equal to 6% of the DA price per MWh.

[33] A random time series has been produced for the utilization of Woking DGs for the provision of STOR power. Each call-off lasts for an hour and hence Woking DGs are called-off as frequently as the annual selected utilization rate. The exact timing of the call-off is of little significance, since we have assumed a constant utilization price for the whole year and since the utilization annual rate is so low that it hardly affects the utilization of storage facilities connected to CHPs.

- The Woking CVPP export prices are determined as follows:
  - EDF Energy pays Woking CVPP the DA price for the half hour time block concerned minus a handling fee, equal to 6% of the DA price per MWh.

We have modelled transfers between Woking CVPP and Woking distributed generators as follows. It is assumed that the Woking CVPP assumes aggregation costs and plans to recover these costs through a variable handling fee with the relevant CHP plants, increasing from 3% to 5% of the gross energy revenues of the CHP operators. For surplus power exported to EDFE's network the gross energy revenues are what remains after deduction of the 6% handling fee charged by the Supplier to Woking CVPP.

The handling fee charged by Woking CVPP to Woking energy end-users is assumed to remain unchanged, i.e. equal to 5% of the EDF Energy top-up import costs. This handling fee is raised to cover administrative expenses (administrative handling of the aggregation services, etc.) and costs for operating the Woking microgrid, including coverage of energy losses.

FENIX application: Balancing services to the TSO
On transfers between Woking CVPP and CHP operators we made the following additional assumptions with respect to the case *Optimised market participation* are:

- When DER provides downward balancing services, the CVPP is getting paid a handling fee which is the same as if the DER would operate and sell power to the DA market (i.e. 5% of the revenues) + a downward balancing handling fee (2% of the difference between DA price and the bid price).
- When DER provides upward balancing services then the CVPP earns a 5% handling fee over gross revenues.

Additional assumptions on transfers between the Supplier and Woking CVPP with respect to the case *Optimised market participation* are:

- When Woking DGs provide downward balancing services the Supplier is still entitled to the 6% handling fee over the contracted energy for the DA market.
- When DER provides upward balancing services, the Supplier is not entitled to a handling fee. This is because the Supplier does not sustain extra balancing risk from this direct contract between Woking CVPP and the TSO. Should Woking CVPP not provide upward regulation according to its offer, the TSO will penalize Woking CVPP and not the Supplier.

FENIX application: Tertiary reserve services to the TSO
The offer made for the provision of STOR services by the Woking DGs is assumed to be part of the optimization that is undertaken by the CVPP[34]. For this reason, it is assumed that a share of the revenues flowing from the STOR market is attributed to the CVPP. Like in the previous cases we assume that 5% of the gross revenues of the availability and utilization payments is withheld by the CVPP as remuneration for their services.

A.3 Assumptions for the future

For making projections of the value of FENIX VPP concepts towards year 2020 a plausible set of assumptions on CBA model parameter values need to be made for year 2020. In this respect, key trends are of importance regarding the electricity-sector regulatory framework facing the distinct stakeholders of our case studies.

In Section A.3.1 we set out assumptions on key parameter values used. These assumptions enable to rerun model simulations of the four FENIX case studies to yield projections for year 2020 of the value of the FENIX concept in specific FENIX applications to distinct stakeholders and to the consolidated electricity system.

[34] Whether the DGs will make an offer for provision of STOR services, the capacity they will offer and the availability and utilization they will ask in return is an optimization itself. This is part of the optimization undertaken by the CVPP.

A.3.1 Assumptions regarding the key parameter values

In the future, parameter values will change due to system developments as well as changes in external policy aimed at security of supply, sustainability and lower energy prices.

Important *drivers* for changes in parameters of various cases in the future include:

- renewables share increases
- fuel & CO_2 price (including the shares of flexible vs. inflexible generation)
- regulatory framework: networks and congestion management
- demand side developments
- storage
- investment cost (e.g. ICT)

These drivers influence the values of seven core parameters in 2020 upon which we will focus hereafter:[35]

- balancing price
- capacity price
- gas price
- electricity price
- price volatility
- level of incentives (renewables only)
- forecast errors (price and volume).

Regarding these core parameters, current UK values (i.e. for the year 2006*)* are:

- balancing price, average SSP: £ 31.31 /MWh, average SBP: £ 46.65 /MWh
- capacity price, average availability payment STOR: £ 6.21/MW
- gas price: average summer £ 13.94/MWh; average winter £ 26.42/MWh
- electricity price, average UK APX price: £ 38.59 /MWh
- price volatility: UK APX = 4,9 (square root of variance of half hourly UK APX prices).
- level of support scheme incentives, LEC level: £ 4.44/MWh
- forecast errors (price and volume). In the Northern scenario only volumes are forecasted. Assumed forecast errors: CHP generation 1%, demand 2.5%. Market prices are assumed to be perfectly predicted.

Below we explain our assumptions regarding the values for these parameters in year 2020 under the baseline scenario expressed at constant 2006 prices. Our assumptions are based on:

- a brief survey of literature: selected documents derive the values for some key parameter values considered here,
- model year 2020 estimates for some key parameter values, such as the electricity price,
- where necessary, resort is made to sweeping assumptions deemed reasonable.

Balancing price

To our knowledge, balancing prices forecasts are not given in any document. Therefore, we tried to derive the change of balancing prices from studies about the additional system costs of an increasing penetration of intermittent sources like wind.[36] Considered studies include ILEX and Strbac (2002), Dale et al. (2004), Strbac et al. (2006), Gross et al. (2006) and Skea et al.

[35] An indirect driver is the generation mix, which influences among others the electricity price through the electricity supply curve (as used in ECN's COMPETES model covering the electricity market in 20 EU Member States). Also price volatility is affected by the generation mix, especially by the share of wind power.

[36] Note: since the model portfolio of Woking does not contain wind generation due to lacking information, forecast errors for wind are of less importance for Woking. However, for the UK as a whole forecast errors are important. If the amount of wind generation in the UK generation mix increases further, the demand for balancing for the system as a whole and consequently the balancing price is expected to increase.

(2008). Gross et al. (2006) was selected as source for estimating the balancing price increase since it is an in-depth review survey of 200 studies. Assuming 20% electricity produced by wind generation, the additional quantity of balancing or regulating power required is in the range of 3-9% of installed intermittent generation capacity (Gross et al., 2006). This assumption of a 20% share for wind power is the highest we found in the literature. It is noted though, that even this high projected share of wind power, compared to the current situation, might not be completely sufficient to meet RES-E targets adopted by the UK government.

The first step is to calculate total additional balancing and capacity costs, with help of assumptions made in Dale et al. (2004). [37] According to the latter a wind penetration level of 20% requires 26.1 GW of installed wind capacity. For wind generation an average load factor of 35% is assumed. Gross et al. (2006) base this average percentage to a share of offshore wind in total wind power capacity of 60%. Furthermore, it is assumed that the required additional regulating power needs to be wholly provided by part-loaded operation of CCGTs. Important CCGT characteristics in this respect are; 85% availability, 10% loss of efficiency due to part loaded operation, O&M costs of £20/kW/year and fuel costs of 1.6p/ kWh (highest estimate)[38].

Combining ranges for additional required regulating power provided by Gross et al. (2006) with the assumptions made by Dale et al. (2004), 3% (9%) additional reserves translate to approximately 780 MW (2,350 MW) additional regulating power in terms *of installed intermittent generation capacity*.[39] These amounts of intermittent wind generation capacity can provide 2,391,480 MWh (7,205,100 MWh) of electricity.[40] If the same amounts of electricity need to be kept as reserve, this requires 357 MW (1.075 MW) of additional CCGT capacity[41] [42] with £45m (£137m) of concomitant additional costs. Assuming that the balancing market also in 2020 will comprise both the approximately 1% of the electricity sales plus additional calculated balancing energy requirements, the amount of energy provided through the balancing market varies from 6,391,480 – 11,205,100 MWh.[43] As a result, additional balancing costs are in the range of £7-12/ MWh[44] of balancing energy, in the absence of any change in profit margin due to changes in market power of suppliers of balancing power. On average, this implies additional balancing costs of £10/ MWh.

We assume that these additional unit costs are fully reflected in *upward* balancing prices, since *downward* regulating power not necessarily has to be provided by CCGT plants. Besides, the market for downward balancing power is more competitive. The upshot is lower or even nil additional balancing costs in the case of downward regulating power. In conclusion, when balancing costs are fully attributed to the market for upward balancing power, prices for upward balancing power may increase by £10/ MWh.

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[37] Gross et al. (2006) use mostly information from Dale et al. (2004) for their calculations. Assumptions made in the other mentioned studies are in line with the assumptions made in Dale et al., which may be seen as a kind of reference study for the UK.

[38] According to Dale et al. (2004), the average price for gas paid by the electricity generators in 2001 was 22.5p/therm, which translates to a fuel cost (assuming 50% thermal efficiency) of 1.32p/kWh. As there are expectations that the gas price will rise, an alternative figure of 27p/therm for 2020 has been used, in line with a DTI paper of 2001 (see Dale et al.). The corresponding fuel price is 1.6p/kWh. These fuel prices include the gas transportation costs for delivery to the power stations.

[39] Calculation of additional costs: 3% * 26.1 GW = 780 MW required balancing power as a percentage of installed intermittent generation capacity.

[40] Calculation in 3% case: 780 MW * 8760 * 0,35 = 2,391,480 MWh.

[41] Calculation of additional required CCGT capacity in 3% case: 2,391,480 / 85% / (1- 10%) / 8760 = 357 MW. This is based on the assumptions for CCGT plants mentioned in the text above.

[42] This calculation method is also followed within ILEX and Strbac (2002) (the SCAR study), see Annex D of this study.

[43] 1% of electricity sales of 400 TWh is equal to 4 TWh. The additional calculated balancing energy requirements amount to 2,391,480 MWh in the 3% case, see footnote 40. Therefore, in the 3% case the total provided energy for balancing purposes is 4,000,000 MWh + 2,391,480 MWh = 6,391,480 MWh. The calculation for the 9% case is done in the same way.

[44] Based on CCGT characteristics and earlier calculations, annual O&M costs and fuel costs have been calculated. O&M costs of £7,137,255 and fuel costs £38,263,680 imply total costs of £45,400,935 per annum in 3% case. Consequently, additional balancing costs amount to £45,400,935/ 6,391,480 MWh = £ 7/ MWh. Calculations for the 9% case are done in the same way.

The latter figure has been used to construct a half-hourly balancing profile for the whole year 2020. This has been done as follows. First of all, for several balancing parameter values for 2006 (SSP, SBP, lowest bid, highest offer), averages and volatility have been determined. Secondly, the SBP values for every settlement period have been determined as weights of average 2006 SBP. Subsequently, the weights have been multiplied by the average 2020 SBP price composed of the average 2006 SBP price and the incremental £10/MWh, resulting in higher price volatility.

Capacity price
Since no estimations of the capacity price in 2020 have been found in the literature, it is assumed that the capacity price in 2020 will double with respect to 2006 in order to meet the increasing demand for balancing. Since the average capacity price amounted to £6.21/MW/hr in 2006 (source: annual STOR report for year 2007/08), this means the capacity price in 2020 amounts to £12.42/MW/hr.

Fuel prices
Fuel Prices for 2020 have been estimated as part of the required input data for the COMPETES model.[45] Estimations have been made for two different scenarios: moderate fuel price and high fuel price scenario.[46] The values for the high fuel price scenario are shown below, since the moderate fuel price scenario it not deemed realistic since it assumes nearly constant prices in 2020 compared to the 2006 price level.

Table A.2 *High Fuel Prices scenario*

Fuel	[€/MWh]	
	ES	UK
Coal	10,01	9,00
Natural gas	26,28	26,28
CO_2 Price	35 €/ton CO_2	

For the UK prices for natural gas and coal are derived from the high fuel price scenario in BERR (2008). The natural gas and coal prices for Spain are based on the same prices for the Netherlands, which are assumed in the Global Economy, High oil Price scenario (GEHP) defined in the scenario study (Farla et al, 2006). Concerning the Spanish coal prices, higher freight costs are assumed to be in place for transporting coal to power plants within Spain. The price of CO_2 emission allowances is realised by trading in the EU ETS market. For this study the average has been used of two assumed values for these allowances in Ozdemir et al. (2008); the low value is €20 per ton and the high value is €50 per ton in 2020.

Electricity Prices, Volatility of Electricity Prices
Electricity Prices for 2020 are an output of the COMPETES model (Ozdemir et al., 2008). Within this model, 12 different prices for a whole year are defined; 3 seasons (winter, summer, autumn/spring) and 4 periods within each season (off-peak, shoulder, peak, super-peak). On basis of these prices, for FENIX two average prices for the year 2020 have been constructed for peak and off-peak periods respectively (peak defined as from 7.00 a.m. till 00.00 a.m., off-peak is remaining period).

[45] COMPETES stands for COmprehensive Market Power in Electricity Transmission and Energy Simulator. This model is based on the theory of Cournot and Conjectured Supply Functions (CSF) competition on electric power networks. Applications of COMPETES include an analysis of the degree of market power of incumbents on NW European electricity markets, an analysis of regulatory measures aimed at mitigation of market power on the Dutch electricity market, an study on the implications of the EU emission trading system on wholesale market electricity prices, Future Electricity Prices (Ozdemir, et al. 2008) and A nodal pricing analysis of the future German electricity market (Hers, J.S.; O. Ozdemir, 2009). In addition, model analyses have been published in peer-reviewed scientific journals and, on numerous occasions, have been presented and discussed at conferences and meetings with experts.

[46] Same assumptions stand for all countries, e.g. high fuel price scenario will influence fuel prices in the same way in both countries.

Since the prices of the COMPETES model are simulated under the assumption of perfect competition, prices are equal to marginal costs and do not take into account market power of generators. Therefore, for peak (off-peak) periods the spark (dark) spread has been added to the marginal costs in order to obtain wholesale electricity prices which better reflect the actual situation in the UK (see Table 8.1 below).

Table A.3 *Electricity Prices in the UK – High Fuel Price Scenario*

Data for 2020	Off-Peak	Peak
Average Marginal Costs (€/MWh)	61,20	63,80
Average Marginal Costs (£/MWh)	47,08	49,08
Dark Spread (off-peak)/Spark Spread (peak) (€/MWh)	7,40	13,30
Dark Spread (off-peak)/Spark Spread (peak) (£/MWh)	5,69	10,23
Wholesale Electricity Prices (£/MWh)	52,77	59,31

The wholesale market electricity prices have been used to construct a yearly time-series of electricity prices in 2020, like has been done in 2006, taking into account that price volatility in 2020 will increase due to the increase of intermittent sources like wind in the generation portfolio of the UK. As a first step, for every settlement period in 2006 the deviation of the average 2006 price has been calculated. Secondly, for each settlement period peak and off-peak prices have been determined as weights of average 2006 peak and off-peak prices respectively. Subsequently, the weights have been multiplied by the average 2020 peak and off-peak prices out of Competes for obtaining a higher price volatility. This resulted in an average day-ahead market price volatility of 5.6.

Level of incentives for CHP

For the accounting year 2006/07[47] the following support levels have been granted in England and Wales:

- for qualifying (high-efficient) CHP and renewables the value of the LEC amounted to £ 4.44 / MWh,
- for qualifying renewable electricity generation only: typical ROC market values in the range of £ 43 – 47 / MWh have been recorded with an approximate average of £ 45/ MWh.

In the UK the Climate Change Levy (CCL) was introduced at 1 April 2001. Initially, non-domestic end users of energy were required to pay a CCL of £4.30/MWh of electricity purchased and used, or purchase renewable electricity instead of paying the levy. The CCL is slightly revised each successive accounting year. With effect from 1 April 2009 the CCL level stands at £4.70//MWh. They can also purchase the LECs rather than the physical power. These certificates are evidence of electricity supply generated from qualifying renewable sources that is exempt from the CCL. The LEC certificates can be redeemed to OFGEM via their suppliers. LEC certificates are issued on behalf of qualifying electricity generators. The latter can bundle LECs with the power they sell to suppliers and in so doing command a premium price. In turn, the supplier can either charge his non-domestic customer the full CCL and fetch this margin or increase his competitiveness by offering a discount tariff.

Electricity generators qualifying for LEC include a range of "renewable electricity" generators, including power generated by the biomass fraction of municipal and industrial wastes as well as coalmine methane. Moreover, so-called quality power output (QPO) electricity that was produced in a fully exempt CHP station or a partly exempt CHP station does also qualify for issuance of LECs.[48]

[47] The accounting years for which the incentive levels are determined in the UK start with effect of 1 April and end on 31 March the next year. Hence, the support levels pertain to 1 April 2006 to 31 March 2007.

[48] Refer to Ofgem (2006), 'Climate Change Levy exemption for CHP; Guidance for exporting 'good quality' CHP generators & suppliers', Issue 5, London, November 2006.

In the absence of relevant information in documents consulted we assume that in 2020 the LEC level will be almost unchanged at a (rounded) level of $£_{2006}$ 4.5 / MWh. We also assume that the technologies qualifying for LEC support will remain unaltered.

It is in order to mention that there is a chance that both the LEC level will be adjusted downward and that the eligibility status of CHP will be downgraded (DEFRA 2007: 9). Reasons for this include the following ones:

- the reference technology against which the GHG emission reduction benefits of CHP have to be assessed is poised to become more energy efficient;
- LEC is also used as a supplementary market support instrument for renewables-based generation. As the cost gap facing renewables-based generation is projected to diminish, support levels required are poised to diminish as well.[49]

In the social cost-benefit analysis we will consider the sensitivity of the results for the LEC transfers. In this analysis all transfer cash flows will be removed for the results of financial cost-benefit analysis, presented here.

Regarding the evolution in the definition of Qualifying Power Output (QPO) electricity from a combined heat and power (CHP) station, we assume the following. Since CHP plants with gas motors are a relatively mature technology, we assume that both electrical and thermal efficiency rise with a low 0.1% per year between 2006 and 2020 (based on expert estimates). Consequently, electrical efficiency amounts to 41.4% in 2020 (2006: 40%) and thermal efficiency to 47.4% (2006: 46%). These assumptions relate to the two CHP units of Woking upon which the case studies are patterned.

Forecast errors
Forecast errors for the quantity of electricity production and consumption depend on the intermittency of the technology deployed as well as the timing of the forecast, especially how much in advance of real-time the forecast is made.[50] Since the Woking demonstration mainly concerns CHP generation, the Northern Scenario CBA model has been limited to the modelling of CHP generation only. Consequently, only the forecast error for CHP generation in 2020 has to be known. As CHP generation is a relatively mature technology and gate closure time of the UK spot market is already limited to one hour, no change of the forecast error is assumed (remains at 1% for 1-2 hours ahead of real-time). The forecast error for demand remains the same as well (2.5%). No estimates have been made for the forecast error for wholesale and balancing prices (like for 2006 prices).

A.4 Assumptions for the scaling up

In 2020, the FENIX concept has the potential to be applied to small-scale DG all over the UK, instead of Woking only as is currently the case. Therefore, we tried to provide insight into the value of FENIX by a limited assessment, focusing on the case of small-scale CHP in the FENIX application Optimised wholesale market participation of flexible DG. This case has been selected since upscaling of other cases would require strong assumptions about the development of balancing and other ancillary services which development is quite uncertain and not supported by unambiguous evidence.

Scope
Although, it is clear that the FENIX concept can be applied to a wide range of technologies both on the supply side and the demand side, the FENIX Woking demonstration project focuses on the utilization of the flexibility potential of CHPs. This potential was harnessed as far as possible by market-based aggregation of small-scale CHP on the basis of gas engines, using ICT-based FENIX intelligence. Gas engines denote a CHP technology that is readily amenable to aggregation, due to their flexibility as well as their size. Gas engines are used for heating of buildings

[49] See also Annex A.2.
[50] Note that the impact of the forecast error depends on the gate closure of day-ahead, intraday and balancing markets, which differs a lot between European countries due to market design.

and swimming pools, and are increasingly deployed with heat storages. Therefore they will most likely dispose of flexibility that still can be harnessed by FENIX type of aggregation devices.

In contrast to gas engines, some other types of CHP generators generally cannot be used for price arbitrage on a quarterly or half-hourly basis due to the character of their production. For instance gas turbines are usually deployed without heat storages and mainly used for industrial processes which require a constant output of heat or steam. If heat or steam demand is low during night, the CHP unit will be switched off and the back-up boiler will be switched on. Consequently, these units have only flexibility on longer time scales than half-hours.

Therefore, we focus on gas engines i.e. reciprocating engines for FENIX-mode flexible deployment in 2020. In 2006, the total CHP capacity in the UK amounted to 5,549 MW_e while natural gas-fired CHP engines amounted to 525 MW_e (BERR, 2007). Hence, in 2006 9.5% of the total installed CHP capacity in the UK in 2006 consisted of reciprocating engines.

According to BERR (2008), 12.1 GW of installed capacity of CHP generators is projected to be in place in 2020. Assuming that the share of reciprocal engines remains equal over time, CHP capacity of gas-fired engines will sum up to 1,150 MW in 2020. In the Woking demonstration project, the flexible CHP capacity amounts to 2.426 MW_e. Therefore, we will use a multiplication factor of about 500 (precise figure: 474) for the upscaling exercise in this chapter.

Price impact
Since it was not possible to model the supply curve of the whole UK energy market for 17,520 settlement periods, a simple assumption is used that the additional direct market access of 1,150 MW of small-scale CHP means a limited price reduction of 10%. This assumption seems reasonable since demand is expected to increase as well up to 2020 (Eurelectric: 1.8% per year as from 2006), limiting potential price effects.

Appendix B Southern Scenario: main assumptions and detailed annual cash flows

B.1 General assumptions

The portfolio considered for the Southern Scenario includes 6 gas-fired CHP units, 2 wind farms and 1 small hydro power plant. The capacities for different DER units are presented in Table B.1:

Table B.1 *DER capacities*

Technology	CHP 1	CHP 2	CHP 3	CHP 4	CHP 5	CHP 6	Wind 1	Wind 2	Hydro
Capacity (MW)	47	12	7.56	2.76	2.72	2.06	49.98	32.3	0.967

Some assumptions needed to be made for the operation of these DER units. The most important one is that DER units are always dispatched before central generation, so that the latter provide the needs not covered by DER, both in the spot market and for system balancing.

Regarding the flexibility that can be provided by DER, it is assumed that all CHP units are 100% flexible, so they can increase or reduce their output to their nominal power or to zero within an hour and their power output can take any value between zero and the nominal capacity. In addition, it is assumed that their efficiency is constant at any operation point, i.e. no efficiency losses are considered for non-nominal production. On the contrary, no flexibility has been considered for wind and hydro plants, as they can only reduce generation and the existence of bonuses discourages the downward balancing.

No electricity demand has been considered for the plants associated to CHP units. The reason is that, according to the Spanish regulation, CHP units sell all their electricity generation to the market and buy their electricity needs from competitive suppliers. What is more, electricity consumption is the same in any case and, hence, it has not been considered in this analysis. Different metering for generation and consumption is only for billing purposes, so the actual exchange with the grid is the difference between generation and consumption.

As for the heat demand of plants linked to CHP units, such demand is considered to be absolutely inflexible. These heat demands have been calculated by applying the heat and electric efficiencies of each CHP unit to its expected electricity production. When downward balancing is done, or when the CHP unit is switched off because market price is not attractive, heat demand is supplied by boilers, whose efficiency is considered to be 90%. When upward balancing is done, extra heat is flared to the atmosphere; it is not stored and, thus, Equivalent Electric Efficiency (EEE) is affected in a negative manner. There are minimum EEE requirements established by the Royal Decree 661/2007 (Ministry of Industry, Tourism and Commerce, 2007a), in order for CHP units to apply for the bonuses. On the other hand, there is an extra payment in case CHP plant efficiency is higher than the minimum requirement, but such payment has not been considered in this analysis. EEE is defined as:

$$EEE = \frac{electricity\ production}{primary\ energy\ consumption - \dfrac{useful\ heat\ production}{0.9}}$$

Since the plants linked to CHP units are using heat, either produced in CHP units or in boilers, they must buy gas to produce it. Therefore, they are, at the same time, producers and consumers. Producers' cash-flows need to be positive, because when they sell electricity, they do so at a price which covers production costs and provides some profit; on the contrary, consumers' cash-flows are negative, since they got the energy service from somebody else and they agree

to pay for it. Hence, the cash-flows of CHP plants might be positive or negative, depending on the difference in cash-flows for production and consumption. However, these cash-flows need to be higher than the cash-flows in which the plants with a do not have such generation unit, and they produce heat in boilers and buy all the electricity they consume.

Another important assumption is that trading decisions are made with full certainty. This means that the CVPP is always able to perfectly forecast market prices and the imbalance direction of the system, so the best decision is always taken with regard to selling in the market, providing internal balancing or providing balancing for the system operator, and the amount of energy to be traded.

B.2 Provision of balancing

CHP units have been ranked, in order to decide which ones should be first used for upward balancing and which ones for downward balancing. For upward balancing, CHP units are downward ranked, regarding the benefits for each extra kWh generated. Benefits have been calculated by considering the bonus of each CHP unit, its variable operation cost and its fuel cost, which depends on both the gas price and the electric efficiency. For downward balancing, CHP units are downward ranked, regarding the costs of each kWh not generated. In this case, the cost of producing heat in boilers has also been considered.

In the cases where aggregation exists (all, except the reference case), there is an internal balancing price. In fact, there is an internal upward price, which is the price to be received by DER units producing more than expected, and an internal downward price, which is the price to be paid by DER units producing less than expected. This internal balancing price is considered for deciding whether to provide balancing or not.

In any case, the CVPP makes no money out of trading this internal balancing, so internal balancing prices reflect the costs for the CVPP:

- If the total imbalance of the DER portfolio reduces system imbalance, no imbalance charges are applied. In this case, both internal upward and internal downward prices are the same as day-ahead market price.
- If the total imbalance increases system imbalance, the CVPP faces a penalty from the System Operator, which is passed through to the DER units increasing such imbalance. DER units who reduce the imbalance are paid or must pay (depending on whether they are long or short) the day-ahead market price. If the system is short, and hence also is the DER portfolio, the *short* DER units must pay an internal price, which covers the CVPP payment to the System Operator and CVPP payment to DER units who reduce the imbalance. If the system is long, the price to be received by *long* DER units is the calculated from the addition of the money received by the CVPP from the System Operator for being long, and the amount paid to the CVPP by DER units who reduce the imbalance.

When internal balancing is done (Cases Active internal balancing and Balancing services to the TSO), the internal price is used for both the price for internal balancing and for imbalances. Therefore, upward internal price is paid by DER units doing downward balancing and downward price is the price received by DER units doing upward balancing. These upward and downward balances increase CVPP incomes and payments, respectively, so they must be taken into account when calculating the price to be paid or received for imbalances.
The maximum upward internal balancing that can be offered *ex ante* is the difference between unit capacity and the amount traded in the market. Likewise, the maximum downward internal balancing that can be provided *ex ante* is the amount traded in the market. The internal balancing actions have to be taken into account, when offering balancing services to the system operator.

Internal balancing is done if all the following conditions are met:

- Total DER portfolio imbalance increases system imbalance.

- CHP generation cost is lower than the price to be paid for the DER portfolio being short (for upward balancing) or CHP generation cost (including boiler cost) is higher than the price to be received for the DER portfolio being long (for downward balancing).
- There is an internal balancing price, which is beneficial for both the CHP units providing the balancing and the DER units increasing system imbalance.
- Internal balancing does not reverse the system or DER portfolio direction, i.e. no more internal balancing is provided after DER portfolio imbalance or system imbalance is compensated, whatever happens earlier, and
- The provision of internal balancing does not bring EEE below the legal threshold established by law.

Additionally, in the Case Balancing services to the TSO, external balancing is done if all these conditions are met:

- CHP generation cost is lower than the price of upward balancing or CHP generation cost (including boiler cost) is lower than the price to be paid for downward balancing.
- There is a system imbalance to be compensated, and
- The provision of balancing does not bring EEE below the legal threshold established by law.

B.3 General methodology for the calculations

In order to estimate the benefits of using flexibility for balancing provision, the different participants in the markets needed to have some forecasting errors. Hence, a series of forecasting errors for each hour needed to be created for DER units, central producers and demand. Those series were created by using random numbers. For each actor, those random numbers followed a normal distribution, whose average value was zero and whose standard deviation was the average forecasting errors provided in next sections.

Since real market data were used and those market data depend on the real system imbalance direction (long or short), the simulations run needed to result in the same system imbalance direction. Therefore, after calculating the forecasting errors for DER units, central producers and demand, the consistency between the resulting system imbalance direction and the real imbalance direction was checked. In case any discrepancy arose, the error of central producers was modified, so that such discrepancy was removed.

However, as these forecasting error series might have a large impact on the results, five series of simulations were run for each case and boundary condition (today, future, widespread deployment of FENIX). The results presented in the main text are the average values of the five series of simulations. By using these average values, all the distorting effects that the use of random forecasting errors might have were minimised.

B.4 Assumptions for today

In each of the boundary conditions selected (today, future and widespread deployment of FENIX), specific assumptions needed to be made. Some real data were available for today conditions (2007) and, therefore, they were the basis for estimating the missing data for today and all the data for future conditions. Real data have been used for all market prices, i.e. day-ahead, imbalances and tertiary regulation, both up and down. Prices were obtained from the websites of the Spanish market operator 0(OMEL) and system operator (Red Eléctrica de España). Real electricity demand in 2007 was used as final consumers' demand (also obtained from Red Eléctrica de España). Reference values were used for estimating the number of consumers (20 million) and the average power contracted by each one (5 kW). These values, together with market prices, the real T&D fees for 2007 and supplier's commercial profit, were used to calculate the money spent by consumers for electricity.

T&D tariffs were constant for all 2007 and their values were 18.16 €/kW/year and 29.815 €/MWh (Ministry of Industry, Tourism and Commerce, 2007b). Supplier's profit was assumed to

be 5%, to cover the required imbalance costs. Demand imbalances are fully born by the supplier and no cost is passed through to consumers. Average demand forecasting error was considered to be 5%. T&D tariffs were distributed among regulated parties (TSO, TNO, DSO, DNO and market operator) according to the data provided by the Spanish regulator (Sub-Directorate for Regulated Systems Regime, 2008).

The existing regulation in 2007 established that a reference gas price must be published by the Spanish Government for the calculation of gas tariffs and the bonuses to be received by CHP units. Such reference price was updated every six months, but it was done in spring and autumn. Therefore, three reference prices were in force during 2007. The weighted average value of these prices, considering the number of days that each of them was in force, resulted in a gas price of 20.61 €/MWh.

In 2007, a new royal decree was issued for the regulation of special regime, which includes CHP and renewable generation in units whose capacity is not greater than 50 MW. According to this Royal Decree 661/2007 (Ministry of Industry, Tourism and Commerce, 2007a), the units included in the special regime can ask for a bonus to be added on top of market price, and they also receive a complement for reactive power, which can be positive or negative, depending on the time and the power factor they use for feeding-in electricity. The bonuses to be received by each DER are presented in B.2, while the complement for reactive power is calculated as a percentage of a reference value. The reference value for reactive power in 2007 was 78.441 €/MWh. The percentages are published in the Royal Decree 661/2007, by dividing the time of generation in three periods (peak, flat, shoulder). In all the cases, DER units provide the optimum power factor, according to the royal decree, and by using the real period distribution in 2007.

The available data with regard to DER generation were the real exchanges with the grid in 2007. For wind and hydro plants, those data could be assumed to be the real generation profiles, but not for CHP. As CHP units are linked to real industrial plants or other type of final consumers, part of the electricity produced by the CHP is consumed inside the site, and not exchanged with the grid. Therefore, CHP generation profiles were estimated from these real exchanges with the grid.

The rest of DER characteristics (forecasting errors, O&M costs and CHP efficiencies) were estimated from common DER literature. Average forecasting errors for CHP units ranged between 2.5% and 10%, depending on unit size; while 30% was assumed for wind farms and 7.5% for the small hydro power plant. Fixed O&M costs were estimated to be about 4380 €/MW/year and variable O&M costs 15 €/MWh for all units. Heat efficiency of CHP plants was assumed to be 60% and electric efficiencies ranged between 30% and 35%, depending on unit size. The main DER characteristics are summarised in Table B.2 below:

Table B.2 *DER characteristics today*

Technology	CHP 1	CHP 2	CHP 3	CHP 4	CHP 5	CHP 6	Wind 1	Wind 2	Hydro
Capacity (MW)	47	12	7.56	2.76	2.72	2.06	49.98	32.3	0.967
Bonus (€/MWh)	19.147	22.122	27.844	27.844	27.844	27.844	29.291	29.291	25.044
Error in DER forecasting	2.5%	7.5%	7.5%	10.0%	10.0%	10.0%	30.0%	30.0%	7.5%
Electric efficiency	35%	33%	31%	30%	30%	30%	NA	NA	NA
Heat efficiency	60%	60%	60%	60%	60%	60%	NA	NA	NA
Fixed O&M costs (€/h)	23.5	6	3.78	1.38	1.36	1.03	24.99	16.15	0.4835
Variable O&M costs (€/MWh)	15	15	15	15	15	15	15	15	15

In all cases, DER units paid 0.05 €/MWh to the CVPP for the services provided. Such payment applied to the electricity actually produced by DER units. Fixed O&M costs for market trading were estimated to be 500 €/year and per traded unit. Therefore, each DER unit spent this amount in the reference case and the CVPP spent 9 times (as 9 units are considered) in the

rest of the cases. No variable O&M costs were considered. On the contrary, investment costs for market trading were assumed to be 500 €/trading party. This means that each DER unit spent such amount in the reference case and that the CVPP spent just the same amount in the rest of the cases.

Different FENIX features added case by case had different investment needs, which were considered to be incremental: 500 € for aggregation (Case Commercial aggregation), 1000 € for forecasting day-ahead market prices (Case Optimised wholesale market participation), 5000 € for being able to modify generation profiles in real-time to provide balancing (Case Active internal balancing), 1000 € for forecasting balancing market prices (Case Balancing services to the TSO).
As for Central producers, they are assumed to have 2% average forecasting error and 10 €/MWh variable O&M costs. No fixed O&M costs were considered for central producers, as they will not affect the cash-flows of other actors, and they will remain constant from case to case. For the same reason, no distribution losses were taken into account, but, as transmission losses make a difference between DER and central generation, they were considered to be 6%.

In order to calculate the fuel spent by central producers, it is assumed that fossil fuel production accounted for 60% of central electricity production, that all fossil fuel plants use gas as a fuel and that they have an average efficiency of 45%, between 30% of traditional plants and 60% of Combined Cycle Gas Turbines (CCGT). However, not all central producers have the same efficiency. Many times, when the system operator needs upwards balancing, such balancing is provided by inefficient plants, whose offers are never accepted at the spot market, but which can help the system operator when upward balancing is required. Likewise, when downward balancing is needed, efficient CCGT or big hydro plants provide such service, as they can reduce rapidly their electricity generation. If CHP units replace low-efficiency plants (30% efficiency assumed) when they offer upward balancing and they replace high-efficiency plants (70% efficiency assumed) when they offer downward balancing, system efficiency might be increased.

B.5 Assumptions for the future

Future calculations used the same assumptions as presented in the section above for today, but some data needed to be adapted to future conditions. In this case, as no real data were available for 2020, estimations were required. Those estimations were based on educated guesses, but they were still estimations, so the resulting conclusions must be taken with care. For comparability purposes, all prices were kept in present value, i.e. inflation was not taken into account for calculating future prices.

The expected international growth in demand for fossil fuels, led to an increase in the *prices of gas and electricity*. Gas price was considered to rise from 20.61 €/MWh up to 26.13 €/MWh. This gas price increase resulted partly in the average electricity price growing from about 39.35 €/MWh up to 70 €/MWh, which means about a 78% increase. All 2007 market prices (for every hour and for day-ahead, imbalances and tertiary regulation prices) were multiplied by the same growing factor, so that both average market price and price volatility were increased. This was deemed consistent with expected trends in the future.

Demand was also expected to grow by 2.5% per year, so the real demand profile for 2007 was increased by the resulting figure of applying such annual growth to the 2007-2020 period. This also implied an increase in the number of consumers up to 30 million.

According to the Royal Decree 661/2007, RES units will receive the *bonus* for 20 years, since the starting up of the plant. Therefore, it is likely that RES units considered in the portfolio will receive no bonus in 2020. As CHP plants do receive payments after 20 years, it was considered that big CHP plants will receive no bonus, medium-sized plants will receive half the amount they receive today, and small-scale plants will receive the same bonus as today.

Due to the improvement in DER generation forecasting, *DER forecasting errors* were expected to be reduced, while improvements in DER technology would lead to a 3% increase in *electric efficiency of CHP plants*.

Assumed DER characteristics for future calculations are summarised in Table B.3.

Table B.3 *DER characteristics in the future*

Technology	CHP 1	CHP 2	CHP 3	CHP 4	CHP 5	CHP 6	Wind 1	Wind 2	Hydro
Bonus [€/MWh]	0	11.061	27.844	27.844	27.844	27.844	0	0	0
Error in DER forecasting	1.25	5%	3.75%	5.0%	5.0%	5.0%	10.0%	10.0%	5.0%
Electric efficiency	38%	36%	34%	33%	33%	33%	NA	NA	NA
Heat efficiency	60%	60%	60%	60%	60%	60%	NA	NA	NA
Fixed O&M costs [€/h]	23.5	6	3.78	1.38	1.36	1.03	24.99	16.15	0.4835
Variable O&M costs [€/MWh]	15	15	15	15	15	15	15	15	15

Improvements would also happen in transmission and in central production, so that transmission losses will be reduced to 5% and the average efficiency of central producers increased to 50%. The share of fossil fuels for central generation is also expected to decrease down to 50%.

B.6 Assumptions for the scaling up

It was assumed that the FENIX portfolio was scaled up 40 times. A widespread deployment of FENIX happens would lead to a much higher penetration of small-scale RES and CHP in the system. This would result in a reduction in market prices, as more efficient units would be participating in the market, but also in the costs associated to DER units. The reduction of market prices due to the increase of small-scale RES and CHP penetration might result in the decommissioning of some central power plants (such as nuclear) and the joining of some big RES plans to FENIX CVPPs. This would lead to a reduction in the production from central power plants, but an increase in the share of plants based on fossil fuels.

For this case most of the assumptions made for the future case were considered to be valid, but some of them needed to be reviewed. It is expected that market prices will be 1% lower than in the future case, while price reduction in O&M costs for DER units would reach 33%. A 33% price reduction is also expected for the investment costs for FENIX. The share of fossil fuel production is considered to be 70%.

DER portfolio characteristics for future calculations are summarised in Table B.4:

Table B.4 *DER characteristics in the scaling up*

Technology	CHP 1	CHP 2	CHP 3	CHP 4	CHP 5	CHP 6	Wind 1	Wind 2	Hydro
Capacity [MW]	1880	480	302.4	110.4	108.8	82.4	1999.2	1292	38.68
Bonus [€/MWh]	0	11.061	27.844	27.844	27.844	27.844	0	0	0
Error in DER forecasting	1.25	5%	3.75%	5.0%	5.0%	5.0%	10.0%	10.0%	5.0%
Electric efficiency	38%	36%	34%	33%	33%	33%	NA	NA	NA
Heat efficiency	60%	60%	60%	60%	60%	60%	NA	NA	NA
Fixed O&M costs [€/h/unit]	15.67	4.00	2.52	0.92	0.91	0.69	16.67	10.77	0.32
Variable O&M costs [€/MWh]	10	10	10	10	10	10	10	10	10