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ALL ISLAND RENEWABLE GRID STUDY UPDATED TO INCLUDE DEMAND SIDE MANAGEMENT

-Confidential-

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Executive Summary

The "All Island Grid Study" [AIGS], published in January 2008 analysed the feasibility of integrating large shares of renewable energies in the All Island power system. However, within this study energy efficiency measures were considered only to very a limited extent, in accordance to the limited policies in place at the time of the study. At the same time the study "Demand Side Management in Ireland" (DSM-study) was published [KEMA08], showing a high potential of DSM measures for efficiency increases in electricity use as well as peak reduction potential for the All-Island system. The results of the DSM study underlined the necessity for the thorough analysis of the additional costs and benefits of demand side measures in the context of the scenarios assumed in the AIGS. The scope of this study is to use results of the DSM study in order to carry out a detailed cost benefit analysis focused on DSM in line with the methodology and scope of the AIGS and provide comparable results.

Review of the DSM study

The focus of the DSM study was on the evaluation of the different energy efficiency opportunities for DSM in the Republic of Ireland. Focusing exclusively on energy efficiency, DSM flexibility measures such as peak shifting and peak clipping actions were not explicitly modelled and evaluated only to a limited extent.

In the DSM study the major uses of the three main fuels (oil, gas and electricity) in the three main sectors of the economy (residential, commercial and industrial) were modelled separately in order to assess the potential energy reduction by using efficient equipment. Three programme scenarios of different scale (in cost terms) and level of ambition were defined, the base, central and aggressive scenarios.

Study methodology and basic assumptions

For a valid comparison of the DSM study with the results of the AIGS, simulations should be executed using the same model, modelling methodology and input data. The majority of the underlying assumptions used in the AIGS have therefore been unchanged. The analysis is performed for the year 2020, following a strictly cost-based approach using the same cost and economic assumptions.

Two AIGS portfolios were chosen in order to investigate the impact of the DSM measures to the system. Portfolio 3 includes a large share of new OCGT while Portfolio 5 is selected to identify the impact of a high penetration of renewable energies (42%). The composition of the chosen portfolios is presented in Figure 1.

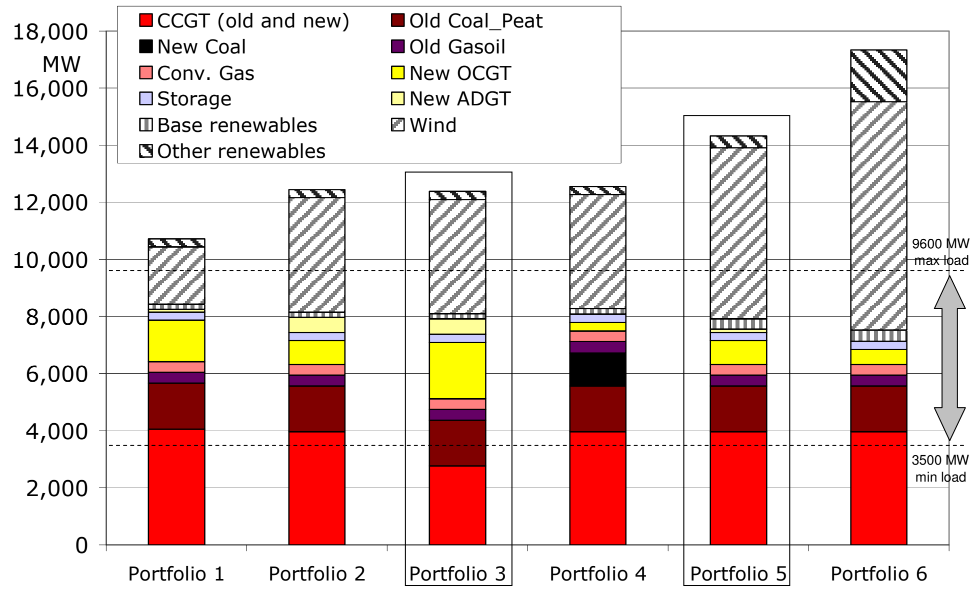


Figure 1: Composition of AIGS 2020 generation portfolios. The chosen portfolios 3 and 5 are highlighted with rectangles.

The load, renewable generation and the resulting dispatch of the generation portfolios for every hour in the year 2020 was simulated using the same methodology and dispatch model applied in work stream 2B of the AIGS [AIGS2b]. The tool was further updated according to the latest model improvements. Due to these improvements the AIGS base case scenarios for the two portfolios were re-run in order to provide a sound basis for comparison. Further, for each portfolio, two DSM efficiency program scenarios from the DSM study are investigated (central and aggressive) corresponding to simulation runs with the same dispatch model but with new energy-reduced demand curves. Two simulation runs for each portfolio lead to a total of four simulations for the efficiency cases. Furthermore, to investigate the impact of new DSM flexibility options, separate simulations are performed for the base demand curves with new versions of the portfolios by replacing OCGT units with peak shifting/clipping DSM units. Two additional simulation runs are therefore performed for the flexibility cases.

DSM modelling framework

Two types of DSM actions are included in the WILMAR model. Efficiency measures are leading to energy savings and flexibility measures are resulting in a more efficient energy dispatch in the system. Hence the general modelling framework consists of the introduction of two modules, the efficiency module and the flexibility module.

1. Efficiency module

The demand curve used in the AIGS and the percentage electric energy savings for each sector presented in Table 1 below are the basis to derive the demand curves for the examined 2020 efficiency scenarios.

Table 1: Electricity savings for each sector for the two scenarios (total final consumption) data from [KEMA08]

Energy (TWh)		Residential	Commercial	Industrial	Total
Perc. 2020 AI Energy	Central	10.3%	21.9%	1.6%	8.5%
	Aggressive	16.7%	23.6%	3.2%	11.9%

The modified demand curve is defined, incorporating the impact of energy efficiency savings to the original system demand curve. To obtain the modified demand curve the annual load profile was decomposed to the load profiles of the main sectors. These load profiles were modified by subtracting the energy savings for the respective sector. Finally, the profiles are added to obtain the modified system demand curve.

2. Flexibility module

Based on the peak shifting and clipping potential, flexible loads are identified and incorporated in the WILMAR Unit Commitment/Energy Dispatch model.

1. *Peak shifting unit:* corresponds to available load (in MW) that can be shifted in time during the day, without implying a reduction of energy demand
2. *Peak clipping unit:* corresponds to available peak load (in MW) that can be reduced on the basis of price signals. Peak clipping results from the reduction of discretionary loads in certain peak periods typically associated with times of high electricity prices. Peak clipping does not result in an increase in demand in another period.

Both unit types are dispatched day ahead and since it was assumed that they need sufficient preparation time to provide the load adjustments they cannot contribute to meeting spinning or replacement reserve requirements on a short notice. Furthermore it was assumed that they start up quickly, with very high ramping rates.

The specification of DSM units with respect to size and costs is a challenging task as both parameters are depending on the policy framework that will be established to promote DSM flexible load participation in the 2020 All Island electricity market. In this study a simple sensitivity analysis was used to determine the parameters at which these units were used by the system. The resulting parameters are presented in Table 2. The operation cost for the clipping units was set to €100/MWh, considering the other fuel costs on the system. For the shifting units, it was decided that €40/MWh difference would need to be seen between peak and minimum daily prices before this unit would be used – therefore, for every MWh of demand shifting, there is a cost of €40/MWh. Six units of 100MW capacity each were considered, so that one DSM unit replaces one OCGT.

Table 2: Characteristics of DSM units

	DSM Clipping	**DSM Shifting**
Number of units	3	3
Maximum capacity of unit [MW]	100	100
Minimum capacity of unit [MW]	10	10
Variable cost [€/MWh]	100	40
Maximum number of hours of clipping at max capacity per day	4	

Comparing these numbers with the current DSM programmes in place it is clear that the payments of current programmes are considerably higher. As the cost-based optimisation reflects only the *variable* costs of the DSM units, further (fixed) payments might be justified by additional system benefits from DSM units. To demonstrate these additional system benefits it was assumed that DSM units replace OCGTs planned to be built in the AIGS. For replacing OCGTs, a similar amount of capacity was replaced- i.e. 600MW of DSM replaced approximately 600MW OCGTs. Hence portfolios 3 and 5 were adjusted by reducing the installed conventional generators by 600 MW OCGT.

Stakeholder impacts

The implications of the DSM measures for the chosen portfolios for the most important stakeholders within the electricity system were evaluated and are presented below.

Generation adequacy and reliability

During the stochastic dispatch simulation, the numbers of critical hours (in which reserve requirements are not met) were identified. Generally the efficiency measures improve system reliability due to the higher reserve margins in the system. These are resulting from the reduction of the system demand if the generation portfolios remain unchanged. The replacement of peak units with DSM units leads to a deterioration of the system reliability for both portfolios due to the characteristics of replacing units: the DSM units present the same reliability as the OCGT they replace but according to the assumptions they do not contribute in spinning and replacement reserve.

Electricity prices

In the case of reliability events, specific price cap levels are allocated by the model, affecting the statistical characteristics of the system prices due to these extreme events.
The efficiency measures and the respective curtailment of the system demand lead to a reduction of the marginal system costs or system prices as compared to the base case. On the contrary, the implementation of DSM units leads to an increase of the prices due to the increased number of reliability events. Excluding these events, the price levels remain in the same levels as in the base case. In accordance to the results of the AIGS, the price

levels in portfolio 5 are lower than portfolio 3 as portfolio 5 employs more efficient CCGT units and renewables.
In this study it became clear that the risk of extreme price fluctuations also depends on the availability of replacement reserve. Looking at the normal system operation (without reliability events), it can be concluded that efficiency measures bring a slight reduction of price fluctuations for both portfolios. The same result can be drawn for the implementation of DSM units in portfolio 3. For portfolio 5 this leads to an increase in the standard deviation of the system price, due to the higher share of wind generation in the portfolio. Including the reliability events, the price fluctuation for the DSM unit cases is doubled, due to the effect of the extreme prices for the reliability events hours.

Total system operational costs and generator revenues

The efficiency measures lead to a reduction in the total operational costs per MWh of the power system of up to 8% in portfolio 3 and up to 10% in portfolio 5. The cost levels chosen for the DSM units are such that the total operational costs of the system remain at almost the same level.

Required investments

The implementation of efficiency measures leads to a reduction of the energy production by conventional generators and hence to a further reduction of their capacity factors. This also implies lower revenues for the generators. Increased revenues are only observed in the case of the DSM units. However this phenomenon is driven by revenues in the hours of critical system, mainly due to the higher marginal prices of these cases.
The AIGS concluded the necessity to adopt measures that ensure sufficient investment incentives for generators to cope with the revenue shortfall. However it was also pointed out, that revenue shortfall is also an indicator for suboptimal generation portfolios.
In almost all cases examined in this study, new plants would require additional (capacity) payments to cover the cost of the investment. Only CCGT and ADGT plants in the DSM unit case of portfolio 3 can fully cover their investment costs in the absence of such additional payments.
These results are very dependent on the operational restrictions of the system. In the original AIGS the OCGT in portfolio 5 were able to recover fixed costs, whereas in the portfolio 5 base case of this study this is not evident. A detailed analysis of the revenues for OCGT revealed that revenues from the provision of spinning reserve were an important source of revenue for OCGT where as in this study, spinning reserve requirements are met by other units and prices are lower.
The increasing revenue gaps observed in this study are not surprising since the examined portfolios were not optimised with respect to an optimal generation portfolio for efficiency scenarios. Hence, there is a clear requirement for the optimisation of the portfolios.

RES-E support requirements

Portfolio 3 presents lower required support payments for all DSM cases, in accordance to the results of the AIGS, an effect that can be attributed to the higher price levels for portfolio 3 compared to portfolio 5. The efficiency measures lead to a decrease of prices and hence to an increase of the required support. The implementation of the DSM units leads to a respective reduction. This effect can be traced back to the behavior of the system marginal prices, which ultimately affect the revenues of the renewable generators; the lower prices due to the efficiency reduction lead to a profit loss while the higher prices in the case of DSM units lead to an increased profit for the generators.

System operation - Provision of reserves

In theory DSM units could be used for the provision of reserves. Such a DSM program is currently in operation in the Republic or Ireland (Interruptible Load/Short Term Active Response - STAR) while current DSM programs as the Economy 7 in Northern Ireland could be used for this purpose also. In the current study, this option has not been explored, since the DSM units were considered to operate only in the day-ahead market without the possibility of a short-term activation. As shown in the reliability results, this leads to an increase in the number of hours when reserve capacities were not met. The inclusion of DSM measures for provision of reserves would (in parallel to avoiding investments in peaking plants) ultimately lead to improved system reliability and consequently to a reduction to the system marginal costs due to the avoidance of reliability.

Environmental impacts - CO_2 Emissions

While the base scenario of portfolio 3 leads to a reduction of 8% relative to the AIGS portfolio 1, efficiency measures increase these savings to 18% for the central efficiency case and 22% of the aggressive efficiency case. For portfolio 5, the savings are increased from 24% (base case, compared to portfolio 1) to 31% in the central efficiency case and 34% for the aggressive efficiency case. For the cases examining the impact of DSM units, no significant additional emission savings are achieved.
Additionally, in all scenarios small reductions in the GB power system are achieved. Thus, emission reductions in the All Island power system are not offset by emission increases in the GB system.

Long-term security of supply

The total amount of imported fuels declines with the implementation of efficiency measures. The main reduction takes place in the gas consumption, due to the high utilisation and increased costs related to this fuel. The reduced fuel imports are not offset by increased electricity imports; rather the opposite appears to occur.

No significant change for the maximum gas demand between the portfolios is observed. The efficiency measures decrease the maximum daily gas demand. These effects are more significant in portfolio 3 compared to portfolio 5.
The efficiency measures lead to an increase in the electricity exports and respective decrease of imports to the all-Island system, while the implementation of DSM units brings no substantial effect to the expected annual energy flows.

Additional costs to society

The key cost and benefit categories discussed are aggregated and illustrated in Figure 2 for the different DSM cases of portfolios 3 and 5. But most of all, the figure provides an aggregation of the costs to society considered in the study in millions of Euros for the year 2020 for the different cases. As can be seen, the efficiency cases lead to cost reductions, while the introduction of DSM units keeps the cost levels almost unchanged. As can be seen in Figure 2, the efficiency cases may lead to annual cost reductions of up to €381 million (portfolio 3) or €321 million (portfolio 5).

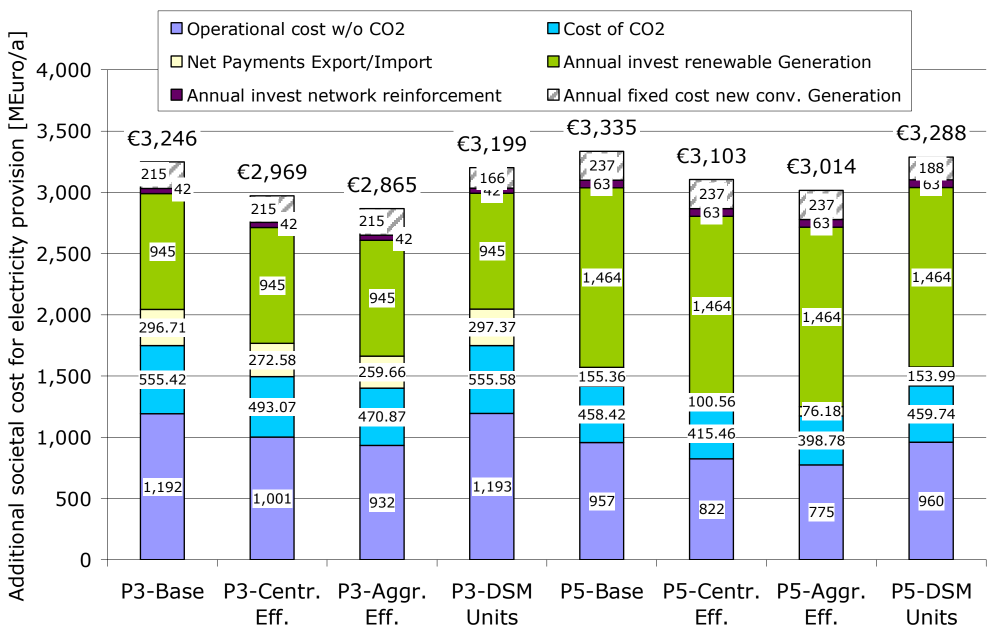


Figure 2: Additional societal costs for electricity provision

The order of magnitude of additional support for renewables ranges between €2.2 and €3.8 /MWh for portfolio 3 and between €6.7 and €9.5 /MWh for portfolio 5. The efficiency measures bring a need for higher support due to the decrease in the electricity prices while the introduction of DSM units leads to a reduction of the required support due to the respective increase in prices.

Main conclusions

Efficiency cases

- With constant generation portfolios efficiency measures increase the reliability of the system as an additional generation is available and can almost always provide sufficient reserve.
- The system marginal prices will decrease with increasing efficiency and a given generation portfolio. Price volatility will also be decreased.
- If the generation portfolios remain constant conventional units will experience lower capacity factors. This will lead to an increased gap of realised and required revenues for conventional generators to finance their capital cost.
- Decreasing electricity prices will also lead to increased RE support requirements.
- Efficiency measures will decrease imports from the GB system.
- Efficiency measures can help to decrease CO_2 emissions. The reduction achieved with efficiency measures in portfolio 3 is almost as high as the reduction achieved due to the addition of 2000 MW of wind in portfolio 5 without efficiency measures (base case). This is due to the fact that 2000 MW of wind provides electricity without emitting CO_2 while in portfolio 3 the CO_2 savings have to be achieved by reducing consumption.
- Efficiency DSM measures may lead to total annual cost savings of €382 million (portfolio 3) or €321 million (portfolio 5).[2] The specific additional costs for each MWh produced remain constant for portfolio 3 and increase slightly for portfolio 5.

DSM unit cases

- The introduction of DSM units into the market can lead to a reduction in the system peak load and peak plant investment costs, but if DSM units are integrated in the system to replace peak plants, it has to be ensured that these units are ready to provide spinning and replacement reserve. Otherwise, the reliability of the system will decrease.

[2] These cost figures do not include costs for the promotion of the DSM programmes

- If DSM units are integrated in the central dispatch at variable cost currently in place with the existing DSM schemes they would not be dispatched under strict cost-minimising principles. If DSM units should play a role in the dispatch, their variable costs must be considerably lower than the present level.
- The main influence of the DSM units on the overall cost for society is saved investment costs. There is only a negligible influence on other cost. The achieved system benefits due to saved peaking capacity may be distributed to the DSM units via a different payment mechanism, e.g. as capacity payments.
- Compared to the base case significant further specific benefits of the flexible DSM units could not be identified yet. However, optimised portfolios and enhanced capabilities of DSM units might reveal additional benefits.

Further work required

A further optimisation of the portfolios is recommended to evaluate an optimal mix of the various generation technologies and DSM units. DSM units have to be further specified with respect to their ability to provide spinning reserve. By conducting a further optimisation, of the portfolios it appears likely, that a cost reduction of the specific MWh produced can be achieved as an additional benefit additional to the CO_2 reductions.

1 Introduction

1.1 Background

In the context of steps to specify an All-Island '2020 Vision' for renewable energy the "All Island Grid Study" (AIGS) was set up to examine a number of options to achieve a substantial share of renewable energy on the island of Northern Ireland and the Republic of Ireland. Results of the study showed that high penetrations of renewable energies could be accommodated by the system [AIGS]. The methodology of the study considered energy efficiency measures appropriate to the limited policies in place at the time of the study. Although the importance of demand-side measures as a complement to increase the penetration of renewable energies has been shown in various studies, the AIGS incorporated DSM measures only to a limited extend. In particular, it was assumed that 50MW of load could be saved and this was simply subtracted from the load curve without further analysis and that the DSM contributes 50MW to spinning reserve (interruptible load).

In January 2008, the study "Demand Side Management in Ireland" (subsequently called the DSM study) [KEMA08] was published, showing a high potential of DSM measures for efficiency increases in electricity use as well as peak reduction potential for the All-Island system. The results of the DSM study underlined the necessity for the thorough analysis of the additional costs and benefits of demand side measures in the context of the scenarios assumed in the AIGS. In September 2008, a joint tender was published by the Department of Communications, Energy and Natural Resources of the Republic of Ireland and the Department of Enterprise, Trade and Investment of Northern Ireland for the provision of an update of the AIGS to include Demand Side Management [DSM-UAIGS].

According to the requirements of the tender, the scope of this project is to use results of the DSM study in order to carry out a detailed cost benefit analysis focused on DSM and in line with the methodology and scope of the AIGS and provide comparable results. For a valid comparison of the AIGS with and without the implementation of DSM options, simulations have to be executed using the same model, modelling methodology and input data. Hence the WILMAR model is used which has originally been used to calculate the AIGS Work Stream 2b modelling results that were further used for the analysis of the AIGS WS 4. The analysis replicates the main parts of the WS 2b, but excludes further analysis (such as transmission network implications) which has not been modelled explicitly in WS 2b of the AIGS. In this context, the main modelling activities in the current project focus on the incorporation of the DSM measures in the framework of the WILMAR model. Although peak shifting and peak clipping DSM actions were not explicitly modelled in the DSM study, these actions are incorporated in the present study in order to investigate the role of load flexibility in the management of the future All-island power system [Ecofys08].

1.2 Structure of the report

This report is structured as follows:

- In chapter 2 a review of the results of the DSM study are presented and discussed and the key findings to be used in the current study are identified.
- In chapter 3 the methodology and the basic assumptions of the study are presented.
- Chapter 4 discusses further the modelling framework for the incorporation of the DSM measures in the WILMAR model based on the results of the DSM study.
- In chapter 5 the stakeholder analysis is performed according to the structure followed in the AIGS.
- Chapter 6 concludes the main results.

2 Review of the DSM study

In January 2008, the study "Demand Side Management in Ireland" for Sustainable Energy Ireland (SEI) was published [KEMA08], on the evaluation of the different energy efficiency opportunities for DSM in the Republic of Ireland. In this chapter we present a review of this study and comment on the data that can be used for the purpose of this work.

2.1 General framework of the DSM study

The DSM study presents an analysis of the ROI residential, commercial and industrial sectors and their usage of three fuels, namely oil, gas and electricity. It reflects on the paths to be followed concerning the achievement of the national energy-savings target of 20% across the whole Irish economy (33% for the public sector), as defined in the National Energy Efficiency Action Plan (NEEAP) [NEEAP07]. According to the framework of the DSM study, DSM is taken to include the reduction in energy consumption and peak demand reduction due to energy efficiency measures.

In the DSM study, each of the three sectors (residential, commercial and industrial) is modelled separately in order to assess the total potential for efficiency gains and peak electricity demand reduction for the different fuels. A model was developed showing the usage of electricity, gas and oil across the three sectors. This usage was broken down further into major end uses (e.g. lighting, heating and cooling) and the potential energy reduction by using efficient equipment was assessed. The assessment thus compares the current use of energy with the most energy-efficient measures that could be adopted. By this comparison, the *technical potential* is calculated, corresponding to the maximum technically feasible energy savings. The *economic potential* is then derived as a subset of the technical potential to reflect the measures that could be introduced economically at present conditions, given the value of savings they would provide versus the cost of implementing these measures. The analysis estimates the savings available in energy usage in terms of GWh/a and percentage savings, against the reference base usage. The reference energy consumption is calculated as the average of the most recent five-year period of energy usage, based on the methodology that is employed in the NEEAP study [NEEAP07].

Further in the framework of the DSM study the ways to capture the economic savings potential are described in terms of examined targets and respective program scenarios. Three energy-savings targets were assessed against the feasibility, the costs and the benefits of meeting them, focusing only on the savings associated with the sectors and fuels examined in the study. The targets were analysed against three programme scenarios of different scale (in cost terms) and level of ambition. These scenarios form the basis for the scenarios undertaken in the current work and are detailed in chapter 3.

The results of the study show that there are significant efficiency opportunities across all fuels and all sectors that would lead to reduced energy use. The vast bulk of these opportunities are available in an economically rational basis.

2.2 Key findings to be used in the present work

2.2.1 Definitions

The DSM study investigates energy efficiency DSM measures across the whole economy of the ROI, incorporating results for the three main fuels, i.e. electricity, oil and gas. Since in the present study the focus is on the electricity system, the results presented in the DSM study concerning energy savings for different types of fuels are not relevant for this work. The basic segregation into residential, commercial and industrial sectors is followed also here and the savings are calculated accordingly for each sector.

Further, the DSM study examines the potential of these sectors for peak electricity demand reduction, expressed in MW. The economic potential is investigated in the time period of 3 p.m. to 8 p.m. and reflects the impact of the energy saving measures to the reduction of peak-time demand. It is not clear from the DSM study whether the peak saving potential corresponds to an average of daily savings or whether the situation at the day with the highest loads is depicted.

The savings potentials are estimated based on the reference base usage, calculated as the average of the most recent five-year period of energy usage, based on the methodology that is employed in the NEEAP study [NEEAP07]. Since the energy consumption in 2020 is different from the reference base, the estimated savings should be extrapolated accordingly. On the other hand, the results of the program scenarios correspond directly to the 2020 case for the ROI, so no further adjustments are needed.

The DSM study provides an insight to the DSM efficiency measures that lead to energy savings but according to our interpretation it does not provide an analysis of peak shifting and peak clipping potentials. In the related literature, peak shifting potential is defined as the amount of available peak load (in MW) that can be shifted in time from peak to off-peak hours of the day and hence does not imply a reduction of energy demand. This definition is in line with [Malik98]. The peak clipping potential is defined as the amount of available peak load (in MW) that can be reduced on the basis of price signals. Peak clipping results from the reduction of discretionary loads in certain peak periods typically associated with times of high electricity prices. Peak clipping does not result in an increase in demand in another period. An industrial customer for example might shut down or halt a production process without rescheduling it for a later time. Commercial or residential customers may be willing to reduce lighting and heating consumption in response to high prices.

All results presented in the DSM study correspond to the ROI. Since the focus of the current study is the All-Island system, all results should be adjusted to include the energy efficiency potential for Northern Ireland also. The segregation used for the energy efficiency measures between the two jurisdictions is based on their total demand: 72% for the Republic of Ireland and 28% for Northern Ireland.

In the following paragraphs, the key figures from the DSM study that can be of use to this work are presented. According to the DSM study methodology, the obtained results are 'additional to the savings that are produced by the current DSM programs as they are already built into the base demand' [KEMA08, p. 5-4].

2.2.2 Electricity energy savings

The technical potential for electricity savings for the ROI is estimated at 6,578 GWh/a and the economic potential at 5,901 GWh/a [KEMA08]. The most significant proportion of energy savings corresponds to the residential sector, where however the least technical potential that is economic appears, as shown in Figure 2.1.

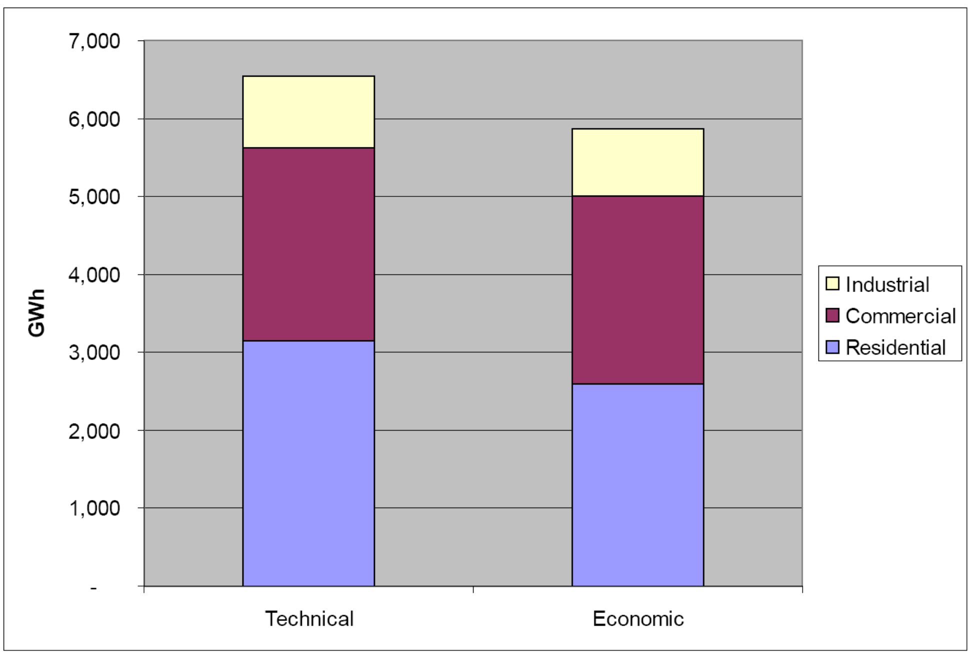


Figure 2.1: Technical and economic potential of annual electric energy savings [KEMA08]

In Figure 2.2, the breakdown of the economic potential for electricity savings by end use for each customer group is presented. As can be seen, lighting is the key contributor to the overall economic energy saving potential.

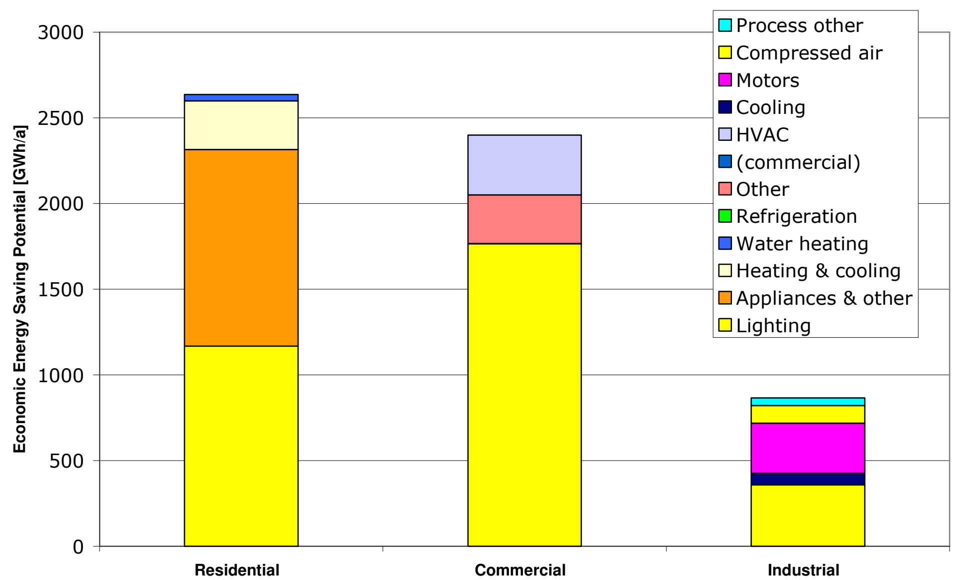


Figure 2.2 Economic energy saving potentials by sector and technology, values from [KEMA08]

2.2.3 Peak saving potential

As discussed above, the DSM study estimates the peak demand reduction due to the efficiency energy savings measures for the period between 3 p.m. to 8 p.m. additionally to the savings that are produced by the current DSM programmes. The peak demand reduction referred in the DSM study corresponds to the levels achieved due to the energy savings and therefore does not account for additional peak shaving that can be achieved by load shifting and clipping. Such measures will be additionally modelled in the current work. In this study we will refer to *peak saving*[3] for peak reduction due to the energy efficiency measures and to *peak shifting/clipping* for peak reduction due to load shifting/clipping respectively.

In Figure 2.3, the technical and economic potential for peak saving according to the DSM study is presented. In total, this technical potential amounts to approximately 1,344 MW, while the economic potential to 1,233 MW. The largest proportion of these savings is derived from commercial customers reflecting their ability to reduce peak time demand through some of the energy efficiency measures, particularly lighting.

[3] This term is in accordance with the DSM study [KEMA08].

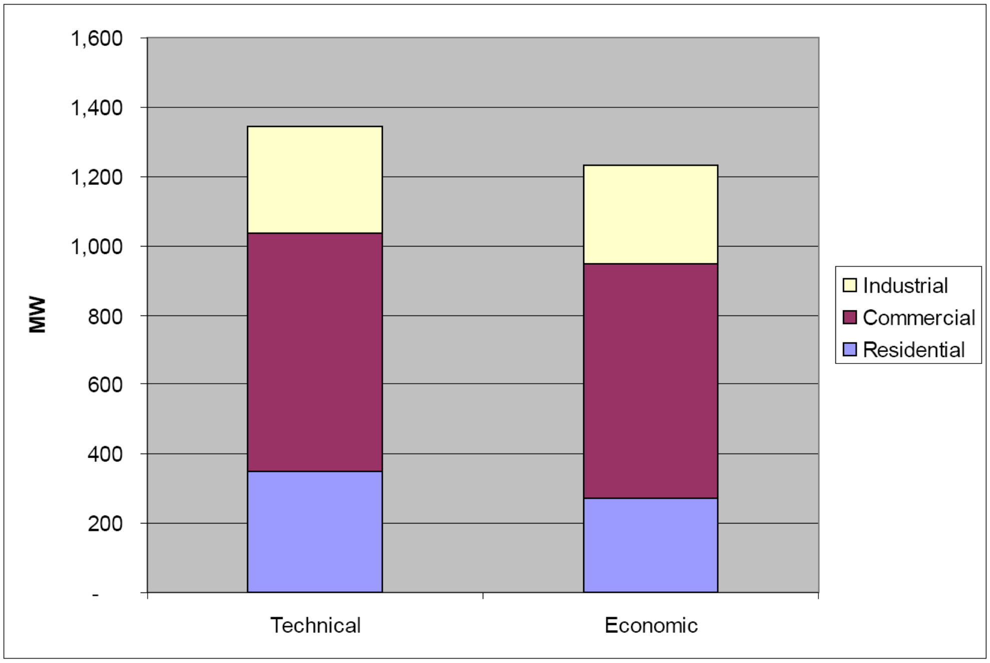


Figure 2.3 Technical and economic potential electricity peak demand reduction [KEMA08]

In Figure 2.4 the breakdown of the economic potential for peak saving by end use for each customer group is presented. In the case of peak saving from residential and commercial load, lighting is the key contributor to the overall potential, while for the industrial load motors can have a large contribution.

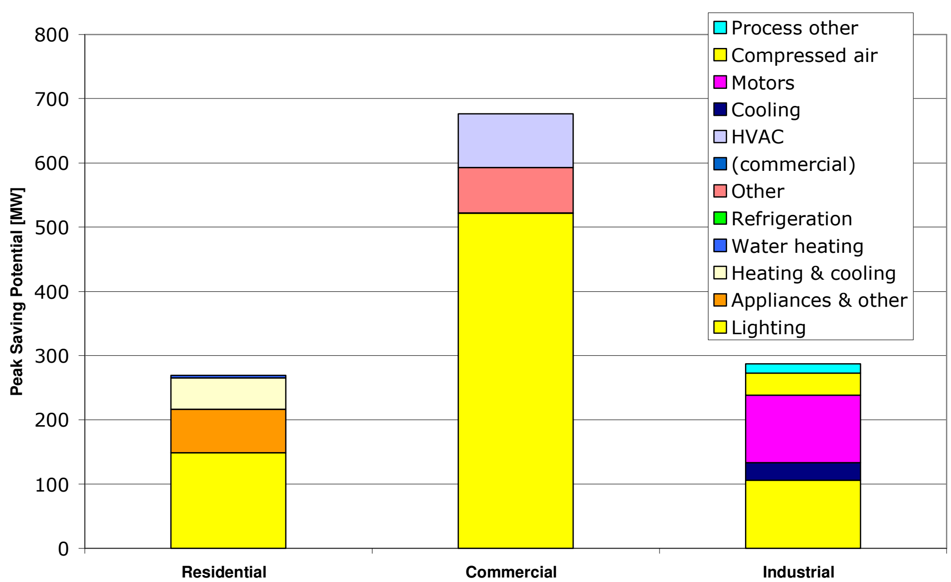


Figure 2.4 Economic peak savings potentials by sector and technology [KEMA08]

2.2.4 Modelled targets and programs

The targets examined in the DSM study were:

1. *2016 target* – A 9 per cent reduction in reference base energy use by 2016 in all fuels in the three sectors. This represents a subset of the whole-economy target articulated in the NEEAP to meet the requirements of the EU Energy Services Directive [NEEAP07].
2. *2020 target* – A 20 per cent reduction in reference base energy use by 2020 in all fuels in the three sectors. As with the 2016 target, this represents a subset of the whole-economy targets being used in the NEEAP – in this case, the main 2020 national energy savings target [NEEAP07].
3. *Aggressive 2020 target* – A hypothetical target to assess the implications of saving 20 per cent of the projected usage in 2020 through a very aggressive series of measures. This target equates to 28,430GWh/a savings in the whole-economy.

These targets were further analysed against three proposed programme scenarios of different scale (in cost terms) and level of ambition:

1. *Base scenario:* The base case was set at a lower, but still ambitious, level to surpass the 2016 target.
2. *Central scenario:* The central case was set at a level of expenditure required to reach the 2020 NEEAP target.
3. *Aggressive scenario:* The aggressive case was modelled with very high levels of programme spending, leading to the realisation of the full economic potential in 2020.

In Table 2-1, the summary results of the DSM study for the electricity savings resulting from these programs for each of the respective sectors are presented for the ROI (Table 6-4, [KEMA08]). These numbers correspond to Primary Energy Equivalent (PEE) and are further used in chapter 4 to obtain the respective energy savings for the All-Island system.

Table 2-1: Summary of year 2020 programme cumulative net GWh savings and net MW savings for the Republic of Ireland [KEMA08].

	Base			Central			Aggressive		
Sector	Res.	Com.	Ind.	Res.	Com.	Ind.	Res.	Com.	Ind.
Energy Savings (GWh)	3087	3329	508	3727	3864	695	6055	4163	1360
Total	6924			8286			11578		
Peak saving (MW)	111	381	65	130	443	89	300	474	173
Total	447			662			947		

2.3 Conclusions

According to the findings of the DSM study, a significant DSM potential for energy efficiency reduction is achievable for the electricity system of the ROI. In the study, the savings potential for each sector is quantified and three main programme scenarios are proposed for the achievement of the targets set by the government of the ROI. In the study, apart from the energy savings due to energy efficiency measures, the respective peak demand reduction (peak saving) is also estimated. The program scenarios developed in the DSM study will form the basis for the current study. Each program scenario translates to a new system demand curve deriving by a respective energy reduction of the original AIGS demand curve. The methodology for the derivation of these demand curves is presented in chapter 4.

During a detailed evaluation of the DSM study the authors noticed, that peak shifting and peak clipping DSM actions were not explicitly modelled in the DSM study. In the context of the present work, these actions will be incorporated separately in the dispatch model, in order to underpin the role of load flexibility in the management of the future All-island power system in the presence of high penetration from stochastic renewable energy sources.

3 Methodology and basic assumptions of the study

A number of framework conditions are introduced in the present study, in order to achieve compliance to the AIGS study methodology and incorporate the results of the DSM study.

3.1 Basic assumptions from the AIGS study methodology

For a valid comparison with the results of the AIGS, simulations should be executed using the same model, modelling methodology and input data. The majority of the underlying assumptions used in the AIGS have therefore been unchanged. A summary of these assumptions are presented below.

1. **Snapshot nature of study:**
   As in the AIGS, the analysis focuses on the performance of various generation portfolios for one particular year in the future (2020). The same assumptions are used concerning the development of the generation system, the network and the implementation of renewable generation by this date.
   Analysing a specific year in the future allows the analysis to be based on a specific time series for load and for a series representing the variable generation of all renewable energy systems. The load for the all island system time series was based on joint projections of the system operators of both jurisdictions. The properties of the assumed time series are presented in the following sections.
2. **Cost based study:**
   A strictly cost-based approach as in the AIGS is followed; a specific market design, market power and strategic bidding behaviour or other elements that are associated with real-world markets are not incorporated and no specific regulatory framework is considered.
   However, for the analysis of revenues of generators, price setting by system marginal prices, based on marginal costs, was assumed. Details on these assumptions can be found in chapter 5.
3. **Interconnection to the system of Great Britain**
   Two interconnectors with a total capacity of 1000MW to the system of Great Britain (GB) are assumed. To model the interactions of both electricity systems, the same basic assumptions about the future generation structure of GB as in the AIGS are followed[4]. Due to some recent developments to the dispatch model, some adaptations were implemented to the model, which are discussed below.

[4] Detailed information about the approach to model the Great Britain system can be found in the appendix of the work stream 2B final report of the AIGS (Appendix 1.5.2).

4. **Treatment of co-firing**
   Co-firing of biomass in peat and coal plants is an option to increase renewable energy generation on the basis of (modified) plants of conventional technology. As in the AIGS, a complete analysis of associated costs and benefits within the study was not possible.
5. **Interest rates**
   A Weighted Average Cost of Capital (WACC) of 8 % was assumed for the calculation of the levelised cost of both renewable and conventional generation in accordance to the AIGS.
6. **Cost assumptions**
   All cost assumptions were based on cost data for the year 2006 and results are reflected in 2006 values. Specific assumptions for costs can be found in the relevant work streams of the AIGS: new conventional generation costs are found in work stream 2A, renewable generation costs can be found in work stream 1, and transmission network equipment and construction costs can be found in work stream 3.

3.2 Generation portfolios

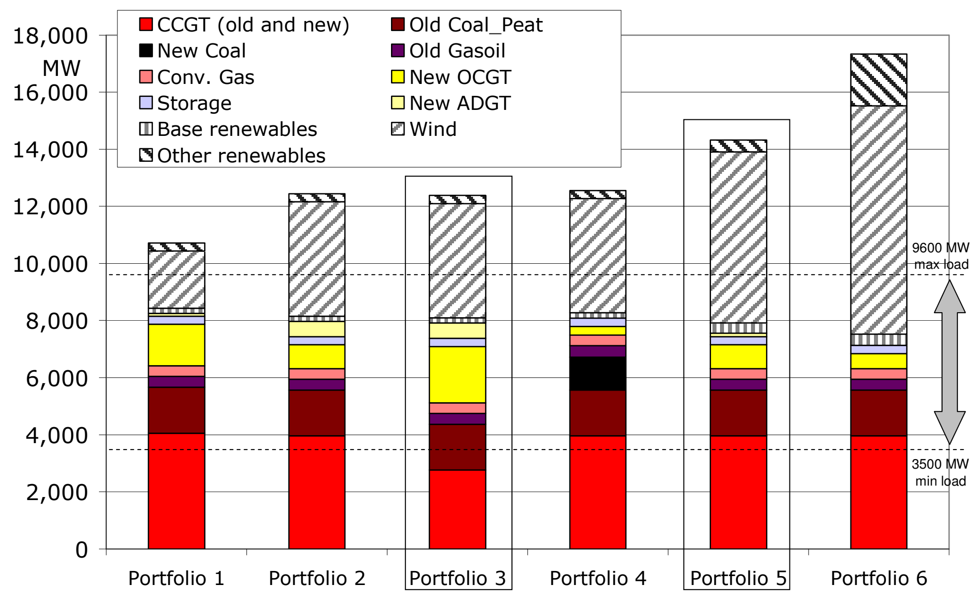
Work stream 2A of the AIGS, "High Level Assessment of Suitable Generator Portfolios for the All-Island System in 2020" [AIGS2a], was designed to generate a number of suitable generator portfolios for detailed study in the other work streams. In total six generator portfolios in conjunction with their associated cost scenarios were examined. In Figure 2.1, the respective portfolios are presented. The portfolios were chosen as to cover as wide a range of cost scenarios and renewable energy penetrations as practical, without however including storage and demand side response. In the current study, a representative subset of these portfolios is chosen in order to investigate the impact of the DSM measures to the system. As in the AIGS, the methodology is based on a linear programming optimisation that produces least cost generation portfolios for a very wide range of future cost scenarios. The cost scenarios include varying fuel costs, carbon costs, renewable resource costs, conventional generation costs, investment costs, network costs etc.

For the current study, the portfolios 3 and 5 from the AIGS have been used. Portfolio 3 includes a large share of new OCGT while Portfolio 5 is selected to identify the impact of a high wind penetration. The portfolios are characterised as follows:

- Portfolio 3 corresponds to a total installed capacity of 12.4GW. The share of renewable energy in total installed capacity is 36%: 4000MW of wind and 470MW of other renewable generation. The conventional generation in this portfolio includes 1603MW of coal generation (including co-firing), 2503MW of flexible gas turbines (Open Cycle Gas Turbines-OCGTs and Aeroderivative Gas Turbines -ADGTs) 2760MW of combined cycle capacity, 758MW of gas turbines (conventional gas and gasoil) and 292MW of storage.

- Portfolio 5 is a very high renewable energy portfolio scenario. In particular, wind capacities are increased to 6000MW and additional baseload and tidal energy systems added reaching a total capacity of 7552MW out of 14.3GW installed (47.3% capacity share). The conventional generation in this portfolio includes higher share of combined cycle capacity (3960MW) but reduced flexible gas turbines capacity (940MW).

In the present study, peak shifting and peak clipping DSM actions are further incorporated in the model in order to underpin the role of load flexibility in the management of the future All-Island power system. These actions are included as separate units in the portfolios. The respective modelling details are presented in section 4.4.



Share of renewable capacity	23 %	36 %	36 %	36 %	47 %	59 %

Figure 3.1: Composition of 2020 AIGS 2020 generation portfolios and respective shares of renewable capacity as of total installed capacity. The chosen portfolios 3 and 5 are highlighted with rectangles.

3.3 Dispatch study

In the dispatch study the load, renewable generation and the resulting dispatch of the generation portfolios for every hour in the year 2020 was simulated in accordance to the Work stream 2B of the AIGS [AIGS2b]. As in the AIGS, for the simulation the WILMAR planning tool[5] was used, adapted to the specific requirements of the 2020 All

[5] The WILMAR (Wind Power Integration in Liberalised Electricity Markets) planning tool is the result of a research project supported by the European Commission under the Fifth Framework Programme. For more detailed information see MEIBOM et al. 06 and related publications (listed for example at http://www.wilmar.risoe.dk/Results.htm).

Island power system. The tool was further updated according to the latest model improvements based on reactions after the publication of the AIGS. These changes are detailed below. Additionally DSM peak clipping and shifting units were included.

3.3.1 Stochastic scheduling model and changes with respect to the AIGS

To perform the simulations of the AIGS, the stochastic scheduling model and an associated scenario tree tool of the WILMAR model had been upgraded to include the integer nature of the unit commitment problem. The scenario tree tool is populated with historical demand and renewable generation (forecasts and actual) time series and generates multiple demand and renewable generation scenarios weighted according to their probability of occurrence. The scheduling model minimizes the expected scheduling cost across the scenarios subject to the operational constraints[6].
For the purpose of this study the original scenario tree of the AIGS was adjusted to the new demand curves due to the DSM energy efficiency measures. The methodology for this adjustment is presented in section 4.3.

3.3.2 Reserve requirements

An important category of operational constraints are reserve requirements. Reserve constraints, spinning and replacement, are dynamically derived from forecast information and dispatch information. Spinning reserve requirements are dependent on the largest online unit and the wind power forecast for the respective hour[7]. According to the AIGS methodology, 150MW of spinning reserve was deducted from the resulting figure to account for the provision from the GB system (100MW) and 50MW provision from the demand side. The replacement reserve requirements correspond to the total forecast error of the power system (load and wind forecast errors, forced outages of conventional power plants)[8]. The scheduling model refines its schedule every three hours to account for the most up to date information (in particular updated wind forecasts).

All operational constraints act as a restriction on the dispatch of plant and therefore, give a different dispatch than would otherwise be the case. For example, the requirement to have a certain amount of spinning reserve provided by the portfolio of plant in a given hour will mean that certain plant therein will be dispatched differently than would have been the case in the absence of this requirement.
The dispatch simulation assumed no transmission network constraints, which complies with the AIGS Work stream 2B methodology.
It was assumed that a second interconnector to the GB power system will be functional in 2020 to reach a total capacity over both interconnectors of 1000MW. 100MW of the in-

[6] The operational constraints are explained in the appendix of the work stream 2B report (sections A 1.4.5 to A 1.4.15)
[7] For details on spinning reserve demand, see section 4.6.1. of the AIGS work stream 2B report.
[8] Replacement reserve requirements are explained in section 4.6.3. of the work stream 2B report.

terconnector import capacity is kept available for spinning reserve, i.e. not used for electricity import.

An important new assumption was introduced, namely that a certain number of conventional base load units have to be online at all times – this was done to approximate the need for ancillary services that were not specifically modelled, such as inertia on the grid and voltage and frequency regulation. Each of the larger units could contribute as either a full unit or half a unit, depending on their size, to this constraint – for example, a 400MW unit would be counted as one unit, whereas a smaller 240MW unit would only count as half a unit. To maintain inertia on the grid, as a first approximation, it was decided that 7 of these units (or more if units only counted as half) needed to be online at all times – 5 in ROI, 2 in NI. This would also have the effect of reducing the cycling of these units, reflecting their limited flexibility.

Additionally, the GB system, which was modelled as one large unit for every fuel type in the AIGS, was altered. For each fuel type, the units were broken down into several smaller units, each with varying degrees of efficiency. This greater resolution of GB would mean more realistic results would be obtained for its operation, with marginal costs reflecting this. This allows flexibility to be included on the interconnector. While it was modelled as being planned day ahead only in the AIGS, it was now assumed it could be planned intra-day. This is possible due to the greater detail used for modelling GB. This means greater use of its flexibility could be possible in the newer version of the model.

The respective fuel cost assumptions are the same as in the AIGS. The cost for CO_2 emission certificates was assumed to be 30 €/t CO_2. The average fuel price assumptions are given in Table 3-1. However, the prices have been modelled with a seasonal variation.

Table 3-1: 2020 Central fuel price assumptions for dispatch simulations in the All Island system (annual averages)

Fuel	Fuel Price Assumption	
	[€/MWhth]	Common Units
Coal	6.9	52.9 €/tonne
Gas (baseload)	21.3	248 €/10^7kcal
Gas (midmerit)	22.0	256 €/10^7kcal
Gasoil	32.3	389.77 €/tonne
Peat	13.4	28.81 €/tonne

Due to these changes, we have decided to re-run the AIGS base case scenarios for the two portfolios in order to have a sound basis for comparison.

3.4 Required simulation runs

As discussed, for a valid comparison of the AIGS with and without the implementation of DSM options, simulations have to be executed using the same model, modelling methodology and input data. The present study focuses on two generation portfolios of the AIGS, in particular portfolios 3 and 5. Due to the changes implemented in the WILMAR model in the latest period, the system dispatch for the AIGS case of the two generation portfolios for the AIGS should be re-run, in order to provide a sound basis for comparison to the new cases.

Further, for each portfolio, two DSM efficiency program scenarios from the DSM study are investigated, the central and aggressive. This leads to simulation runs with the same dispatch model as in AIGS but with new energy-reduced demand curves which represent the respective energy efficiency reduction. Two simulation runs are therefore necessary for each portfolio, totalling four simulations for the efficiency cases.

Furthermore, to investigate the impact of new DSM peak shifting/clipping units, separate simulations are performed with the incorporation of peak shifting/clipping units in the dispatch model. The incorporation of such units leads to the creation of new versions of the portfolios by replacing OCGT units with DSM units. The system operation is further simulated for the base demand curves.

The total number of simulation runs are eight, deriving from specific portfolio/demand curve combination presented in the Table below. The cases of efficiency combined to DSM-modified portfolios are not investigated, due to the lack of information concerning the combined application of DSM efficiency and flexibility measures in the future All-Island system. The specific choice of portfolios and demand curves allows the use of the AIGS cases as basis for the drawing of conclusions on the impacts of DSM efficiency and flexibility measures separately.

Table 3-2: Breakdown of the eight simulation runs of the study

Portfolio	Dispatch Model	Demand curve		
		Base (AIGS)	Central	Aggressive
Portfolio 3	AIGS Updated	1	2	3
	DSM Units	4		
Portfolio 5	AIGS Updated	5	6	7
	DSM Units	8		

4 DSM modelling framework

In the following sections the modelling framework followed in the current study for the incorporation of the DSM actions in the WILMAR dispatch model are presented, tailored to the inputs of the DSM study.

4.1 General DSM modelling framework

Two types of DSM actions can be identified, efficiency measures that lead to energy savings and flexibility measures leading to a more efficient energy dispatch in the system:

1. *Energy efficiency:* all measures leading to a reduction in energy consumption in the system (energy savings). The adoption of energy efficiency measures ultimately leads to a reduction of the system peak. According to the naming convention introduced in Section 2.2, this peak demand reduction will be further referred to as peak saving. These types of measures are in accordance to the modelling framework of the DSM study [KEMA08].
2. *Flexibility:* traditionally this includes measures for the reduction of the system peak by shifting the power consumption to off-peak hours or reducing the peak demand as result of price signals (peak shifting/clipping). DSM flexibility measures may increase the system efficiency and subsequently reduce the total system costs.

These basic categories dictate the modelling framework to be followed for the incorporation of the DSM measures in the WILMAR model. The general overview of the modelling framework is presented in Figure 4.1 and consists of the introduction of two additional modules:

1. *Efficiency module:* a modified demand curve is defined, incorporating the impact of energy efficiency savings to the original system demand curve. This new demand curve is used as input load time-series data for the WILMAR model.
   Update of the scenario tree: the modified demand curves are further used to adjust the scenario tree to be used in the simulation runs.
2. *Flexibility module:* based on the peak shifting and clipping potential, flexible loads are identified and incorporated in the Unit Commitment/Energy Dispatch model of WILMAR. The implementation involves the addition of two models to the WILMAR code to cover a range of peak-shifting and peak clipping DSM configurations.
   a. *Demand curtailment model:* models the reduction of discretionary loads in peak periods where electricity prices exceed a certain threshold. De-

mand curtailment does not result in an increase in demand in another period. This model represents the peak clipping.

b. *Demand displacement model:* models the shifting of electricity usage from one period to another. Typically peak electricity is shifted to off peak. This model represents the peak shifting.

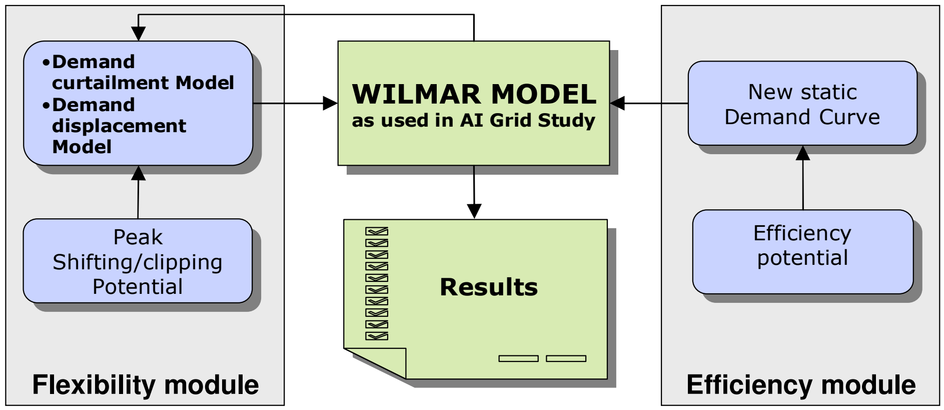


Figure 4.1 Overview of the modelling framework

4.2 Efficiency module: derivation of modified system demand curves

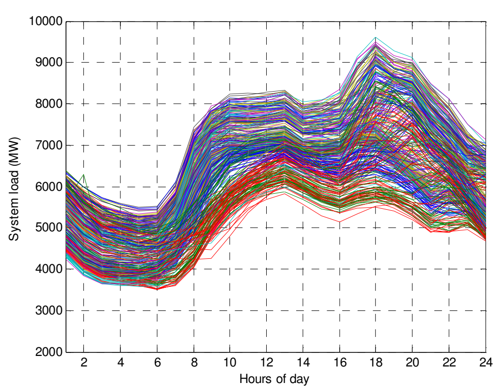
The adoption of energy efficiency measures ultimately leads to a reduction of the energy consumption in the system. This is reflected to a modification of the demand curve and a consequent reduction of the system peak (peak saving). In the DSM study, the yearly values for the energy savings for each sector for the Republic of Ireland are estimated, based on the application of the proposed programme scenarios. In this section, the efficiency measures are incorporated in the demand profile used in the AIGS study and new yearly static load curves are derived, to include energy savings. For this, a three-step process is followed:

3. Decomposition of the annual load profile to the load profiles of the main sectors
4. Derivation of modified load profiles for each sector by subtracting the energy savings due to efficiency measures,
5. Synthesis of the modified load profiles to obtain the modified system demand curve.

4.2.1 Decomposition of load profile

4.2.1.1 2020 All-Island load profile

The 2020 All-Island hourly load profile is created according to the data set used in the AIGS. In particular, the hourly load data for the All-Island system for the year 2003 is projected to the year 2020 assuming an average annual load growth of 3% for the All-Island system for the period 2003 – 2020 [AIGS2a].



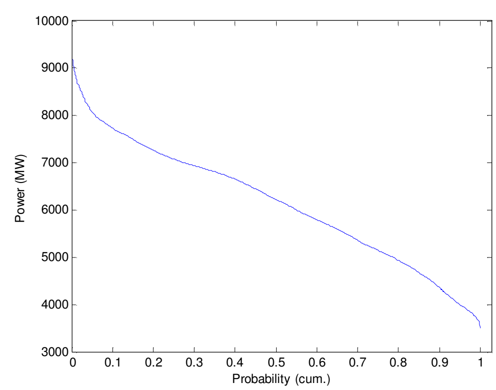


Figure 4.2: 2020 All-Island load profile and respective Load Duration Curve.

In Figure 4.2, the All-Island system load profile is presented together with the respective load duration curve. The dataset corresponds to 8760 hourly values. On the left graph, the 365 daily load profiles are presented; different colours are used for each day of the week. On the right graph, the respective distribution for the hourly values is presented. The system peak corresponds to 9.62 GW, the minimum to 3.51 GW and the mean load to

6.15 GW. The annual energy is 53.86 TWh. The load for the Republic of Ireland corresponds to the 72% of the total while the rest 28% corresponds to the load of NI.

4.2.1.2 Load profiles for the 3 main sectors

In order to comply with the findings of the DSM study, the system load curve has to be split in the 3 main sectors, i.e. residential, commercial and industrial. For this, the standard load profiles (SLP) for 2009 published by the Retail Market Design Service (RMDS) are used [RMDS08]. The SLP correspond to unitised time-series data for 9 major customer groups in Ireland, adapted to the calendar year 2009. In Figure 4.3, the daily patterns for these SLP are presented.

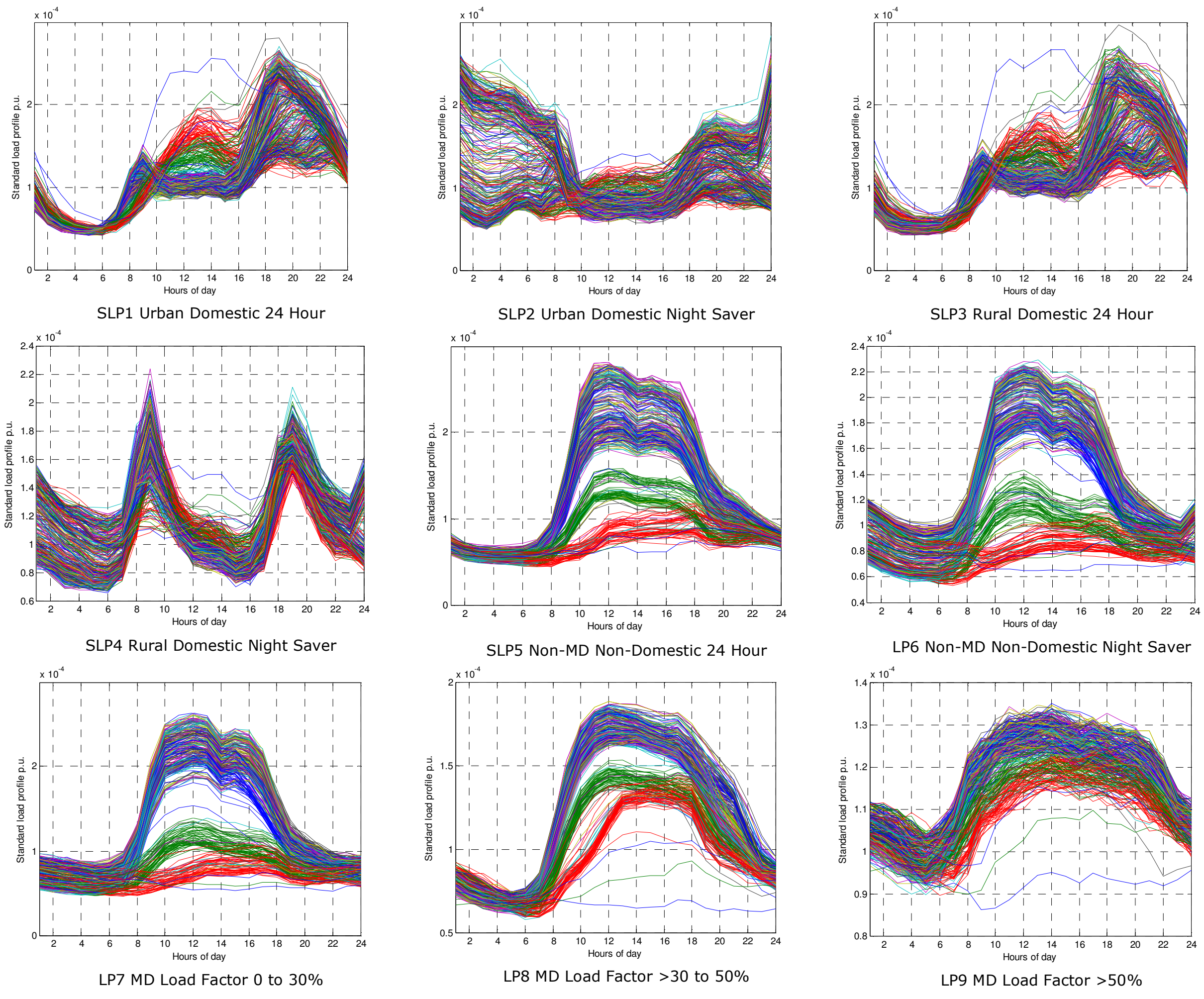


Figure 4.3: Standard load profiles [RMDS08]

To obtain the load profile for each customer group, the unitised SLP are multiplied by the respective energy consumption. Based on the distribution annual sales data for the Republic of Ireland for 2007 [CER08], the breakdown of the energy consumption in the respective sectors is:

1. Residential: 37.5% of total distribution annual sales
   LP1: Urban domestic 24 hour: 19.4%
   LP2: Urban domestic Nightsaver: 5.2% (2.4% day – 2.8% night)
   LP3: Rural domestic 24 hour: 10.5%
   LP4: Rural domestic Nightsaver: 2.4% (1.3% day – 1.1% night)
2. Commercial: 18.2% of total distribution annual sales
   LP5: Non-MD non-domestic 24 hour: 8%
   LP6: Non-MD non-domestic Nightsaver: 10.2% (6.6% day – 3.6% night)
3. Industrial: 44.4% of total distribution annual sales
   LP7: Load factor < 30%: 17.4% (12.5% day – 4.9% night)
   LP8: Load factor 30%-50%: 22.9% (15.3% day – 7.6% night)
   LP9: Load factor > 50%: 4.1% (2.6% day – 1.4% night)

Due to the similarities between the system loads in the two areas, the above percentages were assumed to reflect the All-Island system situation.

Based on these percentages, the annual energy for the 2020 All-Island system is broken down into each customer group and main sector as presented in . These numbers are used for the transformation of the unitised SLP into respective customer and sector load profiles for the 2020 All-Island system.

Table 4-1: Break down of the 2020 All-Island system annual energy into customer groups and main sectors

Energy (TWh)	Residential				Commercial		Industrial			Total
	LP1	LP2	LP3	LP4	LP5	LP6	LP7	LP8	LP9	
Day	10.47	1.27	5.64	0.70	4.29	3.55	6.73	8.25	1.42	42.32
Night		1.51		0.61		1.95	2.64	4.06	0.78	11.54
Total	10.47	2.78	5.64	1.31	4.29	5.50	9.38	12.32	2.19	53.86
Total sector	20.19				9.79		23.88			

If a unified dataset was used one could expect that the load profiles would add up to the system load profile of Figure 4.2. However, in the current study different datasets are used:

- the 2003 All-Island system demand for the derivation of the 2020 load profile,
- the 2009 standard load profiles for the Republic of Ireland,
- the 2007 distribution annual sales data for the Republic of Ireland.

This inhomogeneous dataset makes such a fit not possible. To tackle this problem, the load profile for the industrial sector is obtained as the residual of the system load profile minus the residential and commercial load profiles. In Figure 4.4, the obtained load profiles for the three main sectors are presented, together with the respective distributions.

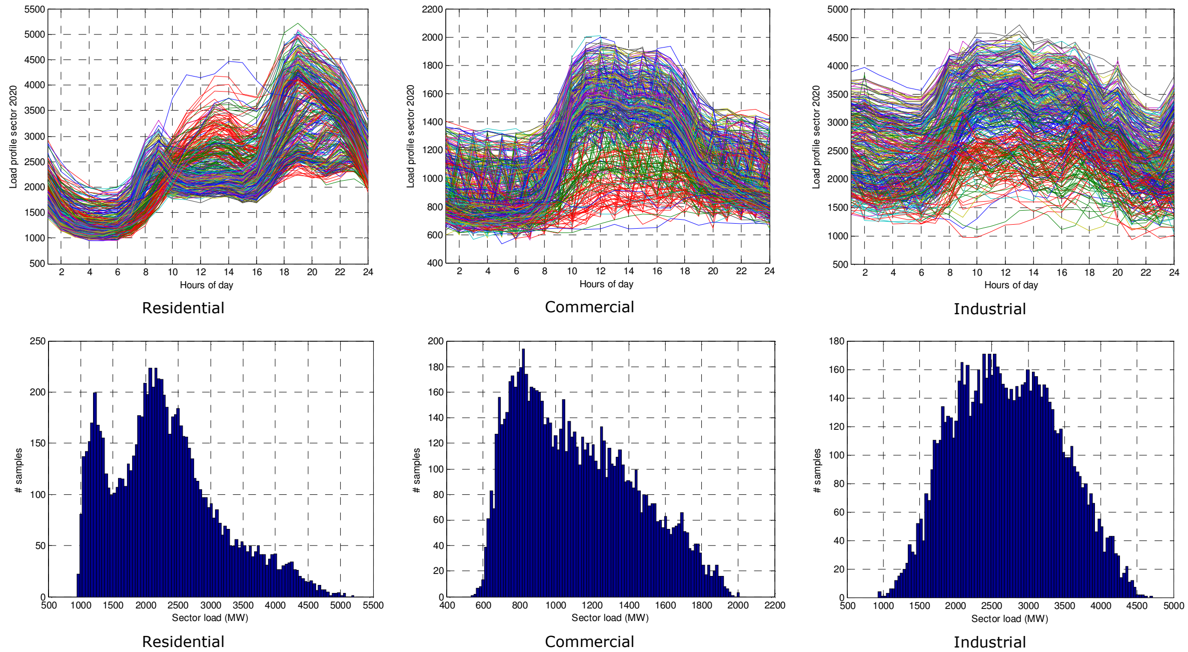


Figure 4.4: Load profiles for the three main sectors and respective distributions.

4.2.2 Modified load profile for each sector

In order to obtain the modified load profile for each customer group, the energy savings should be subtracted from the load profile of each sector. To retrieve the modified demand curve, we assume that the energy savings are uniformly distributed throughout the year. In this case, the modified load curve is obtained by subtracting the same amount of energy from each hour from the respective load profile.

In Table 2-1, the results of the DSM study concerning the cumulative Net GWh savings in primary energy equivalent (PEE) for the three proposed programs for the Republic of Ireland are summarised. These estimates can be extrapolated to the All-Island system (division by 0.72). Further, the values are transformed to Total Final Consumption (TFC) by multiplying by 2.5, according to the methodology proposed in [NEEAP07].

These numbers are presented in Table 4-2 for the two programme scenarios used in the present study. As can be seen, the central and aggressive scenarios lead to respective reductions of 8.5% and 11.9% of the total system annual energy consumption, which corresponds to the 56.1% and 78.5% of the of the annual economic potential[9].

[9] The annual economic potential for electricity savings for the Republic of Ireland for the three sectors is 2.635 TWh, 2.648 TWh and 0.919 TWh respectively, amounting to a total of 5.903 TWh.

Table 4-2: Energy savings for each sector for the two scenarios (TFC)

Energy (TWh)			Residential	Commercial	Industrial	Total
Scenarios	Central	Energy savings	2.07	2.15	0.39	4.60
		Perc. 2020 AI Energy	10.3%	21.9%	1.6%	8.5%
		Perc. Econ. Potential	56.6%	64.5%	32.4%	56.1%
	Aggressive	Energy savings	3.36	2.31	0.76	6.43
		Perc. 2020 AI Energy	16.7%	23.6%	3.2%	11.9%
		Perc. Econ. Potential	91.8%	69.3%	63.2%	78.5%

In Figure 4.5 and Figure 4.6, the modified sector load distributions for the central and aggressive scenario respectively are presented. As can be seen, the uniform distribution of the energy savings throughout the year leads to a respective shifting of the sector load distributions without changing their shape.

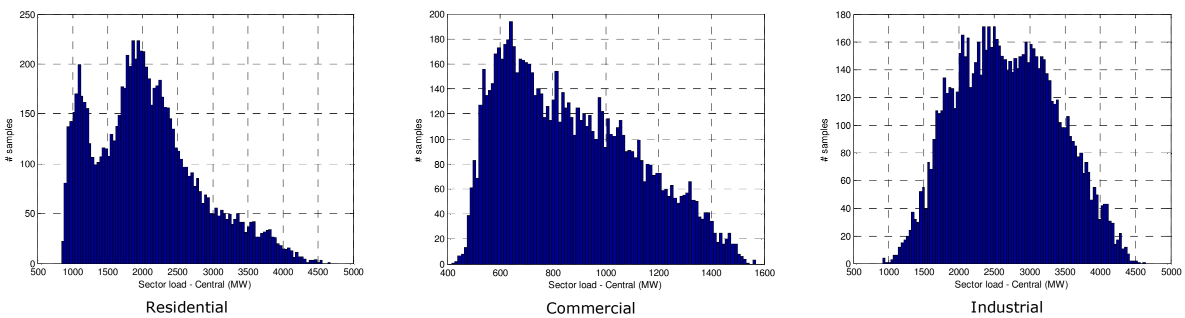


Figure 4.5: Modified sector load distributions for the central scenario.

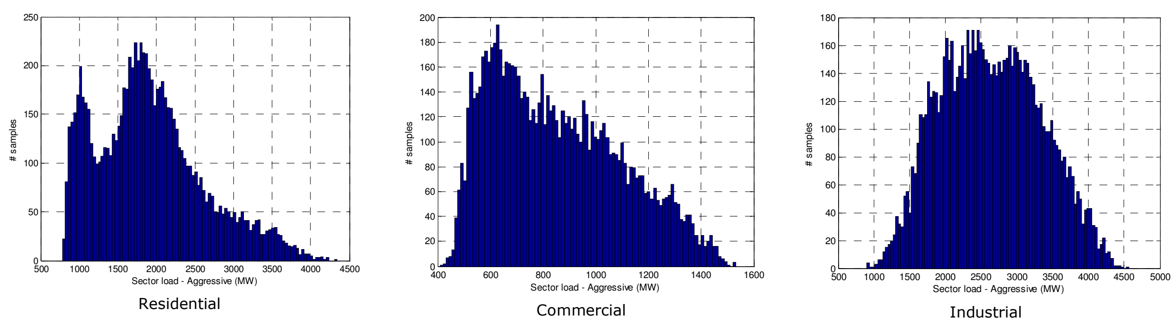


Figure 4.6: Modified sector load distributions for the aggressive scenario.

4.2.3 Modified demand curve

In order to obtain the modified system load profile, the modified load profiles for each sector are added in an hourly basis. In Figure 4.7 and Figure 4.8, the load profiles and distributions for the two scenarios are presented.

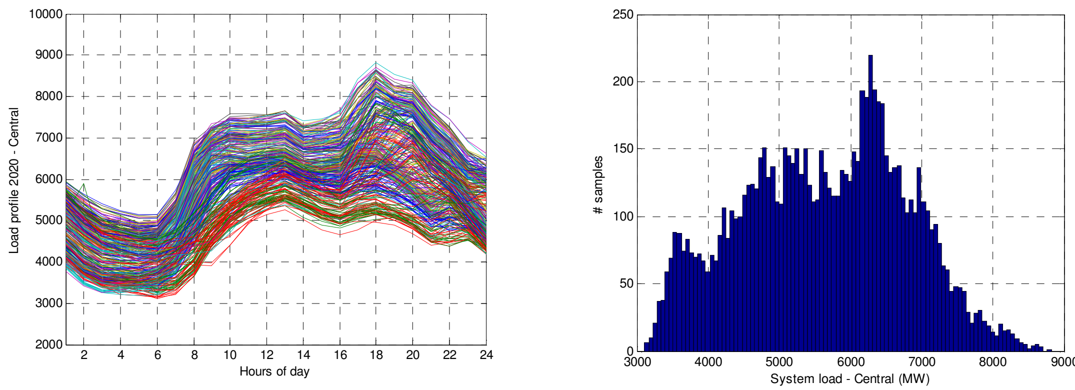


Figure 4.7: 2020 All-Island load profile and respective distribution (central scenario)

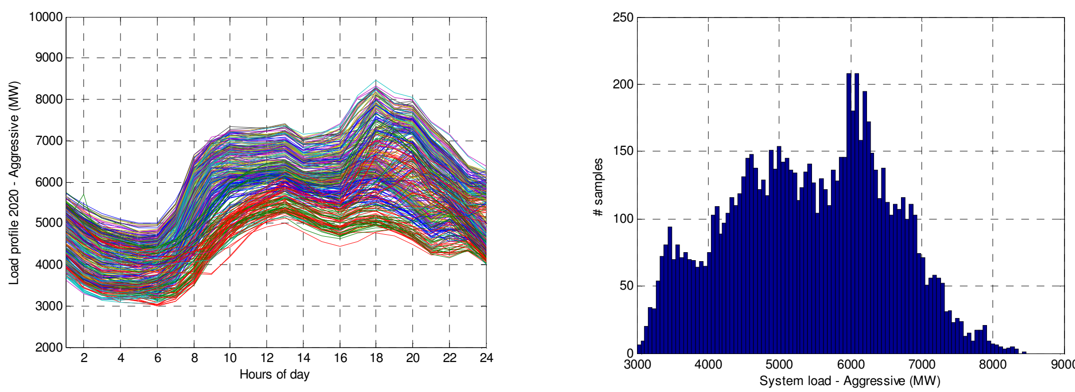


Figure 4.8: 2020 All-Island load profile and respective distribution (aggressive scenario)

The annual energy for each profile is reduced according to the numbers provided in Table 4-2, and this leads to a respective reduction of the system peak (peak saving). For the central scenario this corresponds to 872.3 MW (9% of system peak), while for the aggressive scenario peak reduction amounts to 1244.1 MW (12.9% of system peak). According to the DSM study, the economic potential for peak saving for the Republic of Ireland amounts to 1233 MW. The respective peak savings for the central and aggressive scenarios therefore correspond to 50.9% and 72.6% of the economic potential.

4.3 Adjustment of the AIGS scenario tree

As discussed, the efficiency energy savings lead to the definition of a modified demand curves. This necessitates the respective adjustment of the scenario tree used in the analysis. In Figure 4.9, the methodology followed for the adjustment of the scenario tree is presented. Since the wind uncertainty remains the same, the new scenario tree is obtained as a linear transformation of the original, by multiplying each node with the percentage representing the ratio of the modified to the original demand at the specific hour of the year.

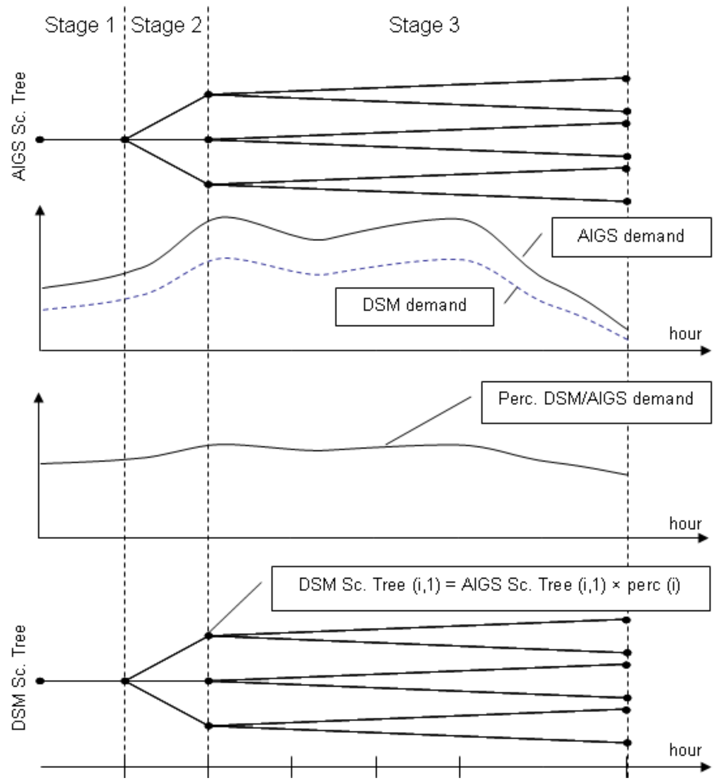


Figure 4.9: Methodology for the adjustment of the scenario tree to the DSM modified demand curves

4.4 Flexibility module: peak shifting/clipping representation in WILMAR

The current DSM measures in Ireland[10] and the framework presented in the DSM study are tailored to traditional power systems with low penetration of variable renewable generation. However, the 2020 All-Island system is expected to facilitate a significant wind power capacity. In such a system, DSM peak shifting/clipping actions can be used to increase the system flexibility and reduce system costs. This necessitates a redefinition and generalisation of the DSM flexibility actions.

In this section, the characteristics for the WILMAR modelling of peak shifting/clipping are presented, together with the specific implementation for the case of the all island system. A fundamental problem for the specification of such units in the dispatch model is the definition of their size and related costs. Both parameters depend on the policy

[10] For an overview of the current DSM measures in the island of Northern Ireland and the Republic of Ireland, one should refer to the joint reviews published by the two TSO's, SONI and EirGrid, [SONIEirGrid06a] and [SONIEirGrid06b].

framework that will be established to promote DSM flexible load participation in the 2020 all island energy market.

In a cost-based, central dispatch optimization, the utilization of the DSM units is of course dependent on the chosen price levels for their operation; cheaper peak clipping/shifting in respect with other system units will lead to more DSM participation. To derive the price characteristics Ecofys consulted experts from the system operator [Eirgrid09] and further performed an initial sensitivity analysis on the system operation for different prices based on deterministic runs of the WILMAR model. Based on these results, prices and sizes for the Irish DSM units were defined.

4.4.1 Modelling characteristics of DSM units

Two types of units were modelled in WILMAR, the peak shifting and the peak clipping units.

- *Peak shifting unit:* corresponds to available load (in MW) that can be shifted in time during the day, without implying a reduction of energy demand [Malik98]. Peak shifting units may be compared to and modelled in a similar way as pumped storage facilities. An additional constraint is added to the pump storage model to ensure that within a certain time frame the total energy exchange is equal to zero. The unit has costs that are equivalent to the cost of peak shifting.
- *Peak clipping unit:* corresponds to available peak load (in MW) that can be reduced on the basis of price signals. Peak clipping results from the reduction of discretionary loads in certain peak periods typically associated with times of high electricity prices. Peak clipping does not result in an increase in demand in another period. It is modelled as an energy limited unit (e.g. a hydro plant) where the energy limit is equivalent to the daily energy that can be curtailed. The unit has costs that are equivalent to the cost of curtailment.

Both unit types are dispatched on the day-ahead market. They cannot contribute to meeting spinning or replacement reserve requirements and are assumed to start up quickly, with very high ramping rates.

4.4.2 Sensitivity analysis on price levels

For the sensitivity analysis, a total of 1000 MW of peak clipping and 1000 MW of peak shifting was included in an initial "test" model run.

1. *Peak Clipping:*

   Five peak clipping units were modelled, each with a maximum clipping potential of 200 MW in one hour, and a minimum of 20 MW. When being planned on the day ahead market, there is a limit placed on how much energy can be displaced by each unit over the entire day - this is chosen as being 800MWh, i.e. each unit can be used to reduce demand at its maximum capacity for 4 ours of the day.

   To model the cost of the ability to clip demand, each unit was given a price per MWh, ranging from 50€/MWh to 110€/MWh, in €15 steps. This is consistent with a range of prices going from the average cost/MWh of existing CCGTs to existing peaking units, to ensure a full range of prices can be analyzed.

2. *Peak Shifting:*
   Five peak shifting units were modelled, each with a maximum sifting potential of 200MW, and minimum of 20MW. These units were modelled as storage units, with an efficiency of 100% - i.e. if 200MW was taken from the load in one hour, 200MWh would need to be added either earlier or later in the day. A constraint was added to ensure that all energy shifted (i.e. load reduced) over the day is added to the generation at another point in the day. Again, prices were set for the operation of these units, with the cost being incurred at the time of load reduction. As the units were only shifting energy, instead of removing it, the costs would have to be lower. The costs examined here were 5, 10, 20, 30, 40 €/MWh. No limit is set on the amount of energy that can be shifted - however, the constraint that was set to ensure the shifted energy increases the load at another time of the day results in a maximum of 12 hours of reduction of load, which would need to be matched with 12 hours of an increase in the load.

The system operation for the portfolios 3 and 5 with the modified demand curves has been investigated based on deterministic runs of the WILMAR model. From the deterministic runs, it could be seen that, as expected, units were used less as their prices increased. Indeed, once a peak clipping unit went to €80/MWh and above, this unit was not used to clip energy. The capacity factor of a unit with a cost of €50/MWh was approximately 9%, which indicated it is used more than a mid merit unit - the maximum capacity factor of the units would be approximately 16% as there is an energy limit which correspond to only 4 hours of usage per day. Therefore, this unit was used more than half of the time it could have been. The next most expensive unit was used far less, with a capacity factor of 1.3% - this is in the range of an OCGT or ADGT unit.

For the peak shifting units, it was again seen that units with a very high cost were rarely used. However, all 5 units were used - the capacity factor of the cheapest unit was 36% (with a maximum of 50%), whereas the capacity factor of the most expensive unit was 0.03%. However, the fact that all these units were used shows that anywhere within this price range a shifting unit would be competitive with some type of conventional plant.

The addition of the DSM units had the effect of increasing the use of the cheaper base loaded units (coal and new CCGT), while decreasing the use of peaking and mid merit units (OCGTs, ADGT, peaking and existing CCGT units). Cheaper units can be used more due to the shifting units flattening the load curve.

The addition of all DSM units at different price levels corresponding to 100MW capacity to the system is seen to reduce costs in the Irish system by €37.02m (2.8%). However, the added ability to make use of the cheaper base load units in Great Britain results in an increase in imports to Ireland. Subsequently, the costs for Great Britain are increased by €26.9m. Therefore, the total system cost reduction is €10.1m.

4.4.3 Characteristics of DSM units for the all island system

After examining the sensitivity results, the final values for the DSM units were decided upon, to be used on stochastic runs. It was decided to examine the DSM units separately from the efficiency measures, so the DSM units were applied only to the base case, i.e. without a reduction in system demand, see Table 3-2. While adding DSM units to the cases with efficiency would have expanded the analysis, it was decided that examining just their effect on the base case would show how these units were likely to impact on the system – adding them to the efficiency cases would not have achieved any more clarity on this.

It was decided that the cheaper units used in the sensitivities were not realistic DSM aggregation options. On the other hand, it became clear that DSM units would never been used, if their costs were too high. Hence, the costs levels used for the analysis were chosen to have an impact on system operation.
The operation cost for the clipping units was set to €100/MWh, considering the other fuel costs on the system.
For the shifting units, it was decided that €40/MWh difference would need to be seen between peak and minimum daily prices before this unit would be used – therefore, for every MWh of demand shifting, there is a cost of €40/MWh. Table 4-3 below gives the characteristics of the units used. The units are split into 6, so that one DSM unit replaces one OCGT – this enables the reliability to remain the same as the DSM units will have the same forced outage as the OCGTs they replace. This was done by using the same forced outage time series for one DSM unit as a corresponding OCGT.

Table 4-3: Characteristics of DSM units

	DSM Clipping	**DSM Shifting**
Number of units	3	3
Maximum capacity of unit [MW]	100	100
Minimum capacity of unit [MW]	10	10
Variable cost [€/MWh]	100	40
Maximum number of hours of clipping at max capacity per day	4	

The question arises, whether the assumed values reflect realistic DSM potentials. Comparing the current programmes in place it is clear that the operational cost would be far greater than the €50-€80/MWh seen in the sensitivity analysis. For example the payments of the Winter Peak Demand Reduction Scheme (WPDRS) are calculated on the basis of three components, as follows [Eirgrid07]

- Total Payment = *reliability payment +Profile payment- Reliability rebate*

According to the data for the winter of 2007, the reliability payment rate is €254/MW per hour while the profile payment is €114/MWh [CER08b].

Obviously these values are considerably higher than the prices assumed in the current study. As the prices used in the cost-based optimisation reflect only the variable costs of the DSM units, further payments appear appropriate that might be justified by additional system benefits from DSM units.

To demonstrate the system benefits of DSM units it was assumed that they replaced OCGTs which were planned to be built in the AIGS. For replacing OCGTs, a similar amount of capacity was replaced- i.e. 600MW of DSM replaced approximately 600MW OCGTs. Hence portfolios 3 and 5 were adjusted by reducing the installed conventional generators by 600 MW OCGT.

5 Stakeholder impacts

In this section, the implications of the DSM measures for the chosen portfolios for the most important stakeholders within the electricity system are evaluated. A common structure with the respective chapter in the AIGS Work Stream 4 [AIGS4] is followed to allow direct comparison with the AIGS results. As discussed in section 3.4, the focus of the analysis is on the AIGS portfolios 3 and 5. For each portfolio, the system operation is simulated for the two new demand curves derived by the efficiency measures proposed in the DSM study (hereafter named *Central* and *Aggressive Efficiency cases*) and for the DSM units modified portfolios with the original AIGS demand curve (*DSM Units case*). Due to the changes implemented in the WILMAR model of the all island power system, the system operation for the portfolios used in the AIGS and the original demand curve is also simulated to be used as reference (*Base case*). The slight differences from the respective outcomes of the AIGS observed in some cases can be attributed to these model changes.

5.1 Common issues

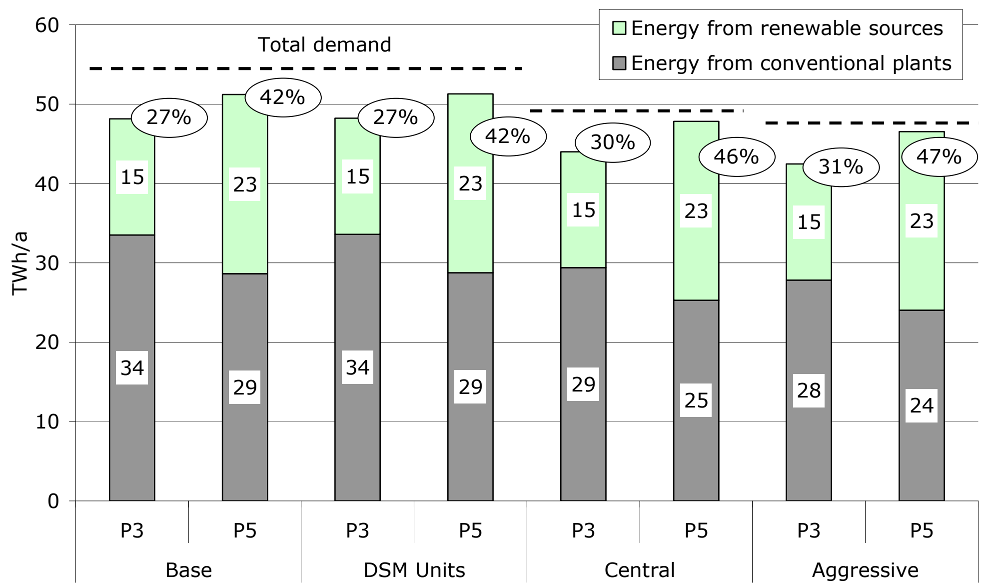
5.1.1 Renewable & conventional energy production

In Figure 5.1, an overview of shares of energy production from renewable and conventional generators as a result of the dispatch simulation for the two portfolios and the respective DSM options is presented. This section also discusses average capacity factors[11]. A detailed discussion of capacity factors of conventional generation can be found in section 5.3.3.

- In portfolio 3, 15 TWh of renewable energy is produced in all DSM cases. Compared to the total demand of the all island system, the share of renewable energy for the base and the DSM units case is 27%, while the reduced demand in the central and aggressive efficiency cases increases this number to 30% and 31% respectively.
- The 2000MW additional wind capacity in portfolio 5 raises the renewable energy production to 23 TWh. The share of renewable energy to the total demand is also increased: 42% for the base and DSM unit cases and 46% and 47% respectively for the central and aggressive efficiency cases.
- Since the renewable energy production is constant for all DSM cases for each portfolio, the capacity factor of renewable generators remains the same, reflecting the renewable energy potential of each portfolio: 37% for portfolio 3 and 38% for portfolio 5.

[11] The capacity factor of a power plant is the ratio of the energy output of a power plant over a period of time and its output if it had operated at full capacity at the same time period.

- The DSM implementation has a sound impact on the capacity factor of the conventional power plants. The efficiency measures lead to a reduction of the energy production by conventional generators which in turn leads to a reduction of the capacity factors: for portfolio 3 the capacity factor drops from 48% in the base case to 42% for the central and 40% for the aggressive efficiency cases, while in portfolio 5 this reduction is from 43% to 38% and 36% respectively.
- On the other hand, the substitution of peak power plants with DSM units in the respective cases leads to a reduction in the total capacity of the remaining conventional units in the portfolios which has a positive impact to the capacity factor of the conventional generators. In particular, for portfolio 3 the capacity factor is increased from 48% to 53% and for portfolio 5 from 43% to 47% respectively.



Capacity factor ren. generators	37%	38%	37%	38%	37%	38%	37%	38%
Capacity factor conv. generators	48%	43%	52%	47%	42%	38%	40%	36%

xx % Renewable energy share in total annual demand

Figure 5.1 Conventional and renewable energy production, total annual demand of the all island system and capacity factors for Portfolios 3 and 5 for the different DSM options

5.1.2 Generation adequacy

In the AIGS, the reliability analysis is performed from the generation perspective in work stream 2B and from the network perspective in work stream 3. Since, the network perspective is out of the scope of the current study, our focus has been on generation reliability. The general conclusions on this subject are presented in this section.

In the methodology followed in the AIGS, in order to make the portfolios comparable from a reliability perspective, the compositions of generation plants in the work stream 2B portfolios were tuned such that each would meet the same, predefined standard for Loss of Load Expectation (LOLE). The Loss of Load Expectation is a quantitative expression of the adequacy of the generation plant with respect to the load. The LOLE gives the number of hours in a year during which the available generation plant will be inadequate to meet the instantaneous demand. In line with current practice, AIGS work stream 2B required that LOLE should be not more than 8 hours annually. As LOLE is a statistical measure, this does not mean that during this limited period a deficit affecting end users actually occurs in every year.

As discussed in the AIGS, the methodology applied in the model makes it difficult to derive the reliability levels of the portfolios. First of all, the datasets for load and wind power contain exactly one year, i.e. 8760 samples. This is a quite limited dataset, particularly when trying to evaluate differences in the sub-‰ range. The combinations between wind power output and load values in the model do not cover the complete range of possible data and, hence, with other input data the outcome of the LOLE assessment may easily vary by a magnitude that would change the order between portfolios.

In the current study, no further tuning of the portfolios with respect to reliability has taken place. The portfolio configurations derived from the original tuning of the portfolios were further used in the different DSM cases in order to isolate the impacts of the DSM measures to the portfolio reliability. During the stochastic dispatch simulation, the number of critical hours was identified. Figure 5.2 presents the respective results.

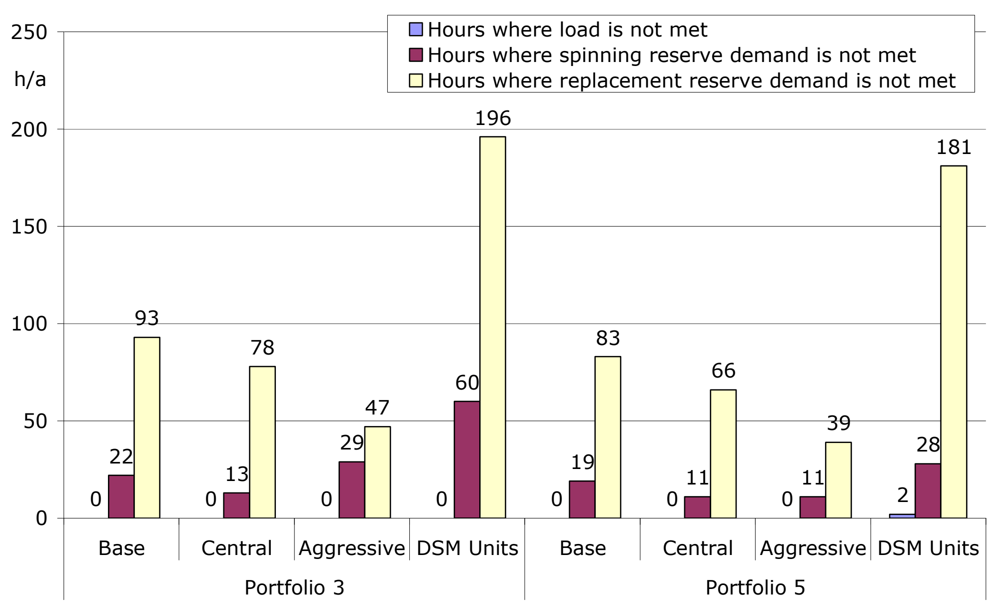


Figure 5.2: Number of hours with generation reliability problems

Some discrepancies are observed between the obtained results for the base case and the respective original AIGS results (not represented in the graph). In particular, the hours where spinning reserve demand is not met are increased from 1 to 22 for portfolio 3 and from 3 to 19 for portfolio 5. The hours when load is not met, however, have now been reduced to zero. This is due to the changes implemented in the WILMAR model – when there are a minimum number of units online, the chances of losing load are reduced, but these units may not be as good for providing spinning reserve. Also, with intra day flexibility on the interconnector, units which otherwise would have been online are now offline and cannot provide spinning reserve.

What can clearly be seen in Figure 5.2 is that efficiency measures improve system reliability, which is expected due to the reduction of the system demand and the resulting spare capacity of the system. An exception to this general observation is the number of hours where spinning reserve demand is not met for the aggressive efficiency cases. This may be due to the fact that, with intra day flexibility and extra efficiency, slow units which would otherwise have been online and could provide replacement reserve are now offline, and have been replaced by the smaller quicker units, which now cannot be used to provide replacement reserve.

The replacement of peak units with DSM units leads to a deterioration of the system reliability for both portfolios. This effect is actually the ‘price to pay’ from the avoided investment in redundant generation and is expected due to the characteristics of replacing units: the DSM units present the same reliability as the OCGT they replace but according to the assumptions they do not contribute in spinning and replacement reserve. Therefore, the number of hours where load is not met remains unchanged but the hours where spinning and replacement demand is not met increase respectively.

As can be seen, the two different DSM measures have diverse impacts to the system reliability and economics. Efficiency measures improve system reliability but require capital investments, while the used design of peak shifting/clipping deteriorates the system reliability but reduces the generation portfolio investments. It can therefore be concluded that a combination of the two measures is the optimal solution, leading to a cost reduction for the generation system without major impacts to the system reliability.

5.1.3 Price duration, average prices

As discussed in the AIGS, it has to be pointed out, that the absolute price values derived by the analysis have to be interpreted with extreme care and no judgement on the suitability of portfolios can be made without consideration of the limitations of the study. Firstly, these numbers do not represent the full cost for society since investments in network or generation are not included. Secondly, a number of effects that influence prices in the real world are excluded from the model.

In particular, in the case of reliability events presented in Figure 5.2, specific price cap levels are allocated. These price levels and the related events are:

1. €4000 for all hours that load is not met
2. €400 for all hours that spinning reserve capacities are not met
3. €120 for all hours that replacement reserve capacities are not met
4. €120 for all hours where other restrictions are not met (e.g. minimum reservoir level of pumped storage, minimum number of units online)

Figure 5.3 shows the weighted average price occurring in the system dispatch based on system marginal costs. In order to distinguish the impact of the reliability events, the respective values are calculated separately for all the hours of operation (case with reliability events) and for the set of hours excluding reliability events (normal operation). As can be seen, the efficiency measures and the respective curtailment of the system demand lead to a reduction of the system prices as compared to the base case. On the contrary, the implementation of DSM units leads to an increase of the prices due to the increased number of reliability events. Excluding these events, the price levels remain in the same levels as in the base case.

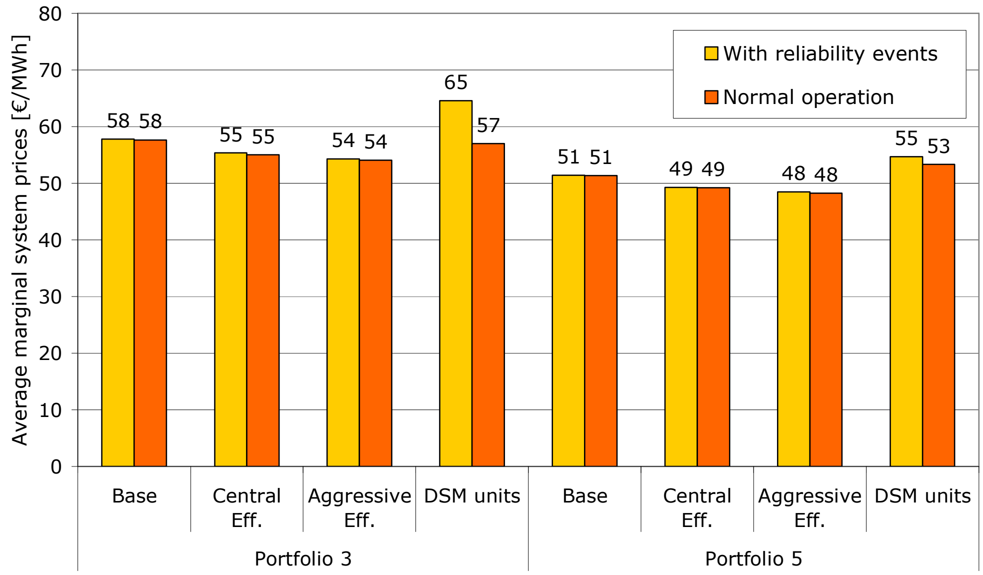


Figure 5.3: Average "price" levels in the different cases for the portfolios 3 and 5 (volume-weighted marginal system price as calculated on a cost basis)

In Figure 5.4, the hourly prices in descending order for all scenarios for all 8760 hours of the year are presented. These values reflect the system marginal prices or wholesale market prices that define the revenues of all generators.

Looking from left to right, we observe a number of high or even extreme prices, corresponding to the reliability events presented in Figure 5.2 (values above €140/MWh are not graphically represented due to the scaling of the graphic).

In accordance to the results of the AIGS, the price levels in portfolio 5 are lower than portfolio 3 as portfolio 5 employs more efficient CCGT units and renewables. For both portfolios, the efficiency measures lead to a shifting of the base price curves to the left and towards lower prices, reflecting the respective reduction of the system costs due to the reduced energy demand. In the DSM unit cases, the increased number of hours when replacement reserve demand is not met lead to an accumulation of hours with values at €120/MWh. This leads to a shift of the respective price curves to the right and a respective increase in the average prices.

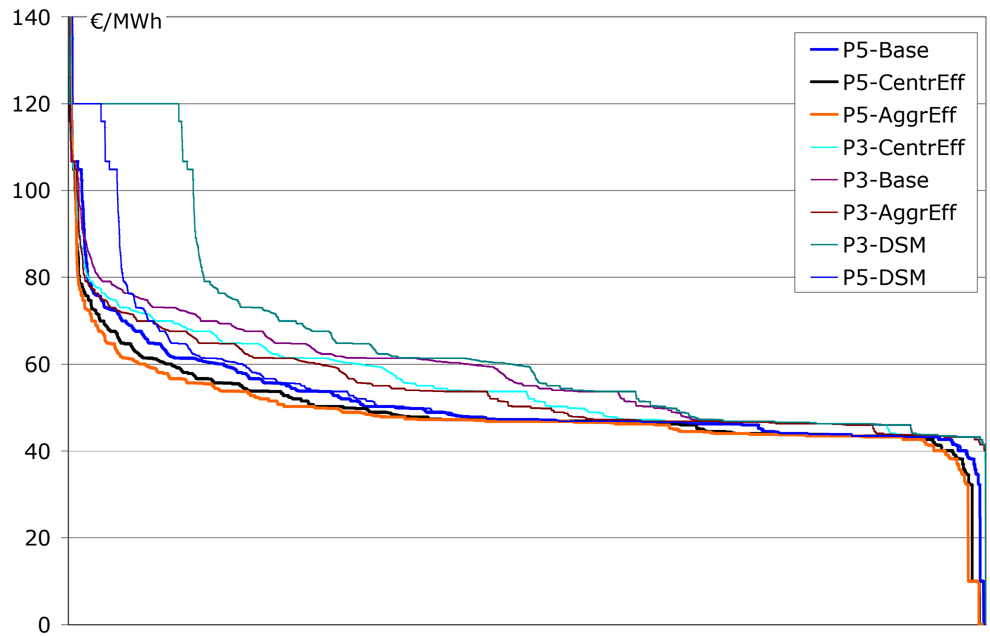


Figure 5.4: Price duration curves for all DSM cases for portfolios 3 and 5

5.2 Price volatility

Since this study is cost based and does not consider a specific market design, only general consequences of each portfolio can be considered in relation to price volatility. The optimisation methodology applied in the dispatch model represents a continuous redispatch every three hours. In contrast, most real-world electricity markets are based on day-ahead power auctions, in some cases in combination with one or several intraday-markets. Therefore the following observations are not necessarily applicable for real markets.

For participants in the electricity market the risk of changing prices has to be managed. The effects of increased penetration of variable renewable electricity on price volatility are manifold. Generally portfolios with higher shares of renewable electricity result in higher short-term price risk due to variations of the resource. In this study it became clear that the risk of extreme price fluctuations also depends on the availability of replacement reserve. Figure 5.5 shows the standard deviation of the marginal system price for the whole set of samples (with reliability events) and the subset corresponding to normal operation. Looking at the normal operation subset, it can be concluded that efficiency measures bring a slight reduction of price fluctuations for both portfolios. The same result can be drawn for the implementation of DSM units in portfolio 3. For portfolio 5 this leads to an increase in the standard deviation of the system price, due to the higher share of wind generation in the portfolio. Including the reliability events, the price fluctuation for the DSM unit cases is doubled, due to the effect of the extreme prices for the reliability events hours.

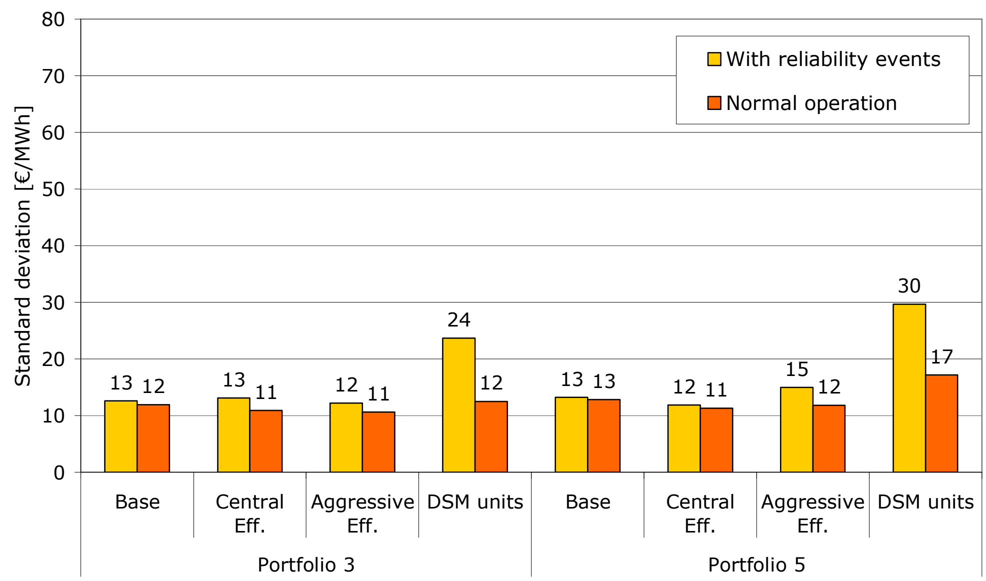


Figure 5.5: Standard deviation of marginal system costs (electricity "prices")

5.3 Impact on Generator units

5.3.1 Characteristics of conventional generation units

Following the methodology of the AIGS, for this analysis generators are grouped according to technical characteristics such as plant efficiency and plant flexibility (defined by factors such as ramp rates in MW/min, minimum up- and downtimes, startup fuel consumptions, synchronisation times and capabilities to provide operating reserves) in the following groups:

- **Existing Coal and Peat**: with average maximum efficiencies of 37 % and relatively low ramp rates (peat plants in particular have about 1-2MW/min, old coal plants can ramp at 4-6MW/min).
- **Existing Gasoil:** open cycle gas turbines that run on gasoil and reach maximum efficiencies of only 30 %, mainly used for the provision of replacement reserve. Ramp rates for these plants range between 5 and 10MW/min.
- **Conventional Gas:** two existing condensing thermal plants running with gas with maximum efficiencies of up to 40 % and ramp rates of 2 and 4MW/min.
- **CCGT**: combined cycle gas turbine plants (both existing and new) with maximum efficiency in excess of 50 %. New CCGT plants are assumed to reach ramp rates of about 11MW/min.
- **New OCGT**: open cycle gas turbines are expensive peaking plants with capacities close to 100MW but with maximum efficiency limited to 36 % and ramp rates of 10MW/min.
- **New ADGT**: aeroderivative gas turbines are very similar to OCGT, but have higher efficiencies of up to 46 % and the ramp rates of 10MW/min. The start-up fuel consumption of OCGT and ADGT when cold is only about 0.25 % of the start-up fuel consumption of a CCGT plant. Due to their flexibility, they can offer a higher share of their capacity as spinning reserve.

Unit groups with higher operational efficiencies tend to have higher investment costs. Assumptions on investment costs are given in Figure 5.12.

5.3.2 Total investment volume for new conventional units

In Figure 5.6, the annuity for the investment in new conventional generation, calculated on the basis of cost assumptions given in Figure 5.12 is depicted. The figures include annual fixed operating cost such as maintenance and payroll costs that do not depend on energy output. These investment costs are aggregated with the other cost components to be carried by the final customer and need be recovered from payments received in the energy and reserve markets and from payments under a capacity payment mechanism[12].

As can be seen, the replacement of peak OCGT plants by DSM units leads to a respective reduction of the investment and fixed operating costs of about €50 million annually.

[12] This topic is further explained in section 5.6.3.

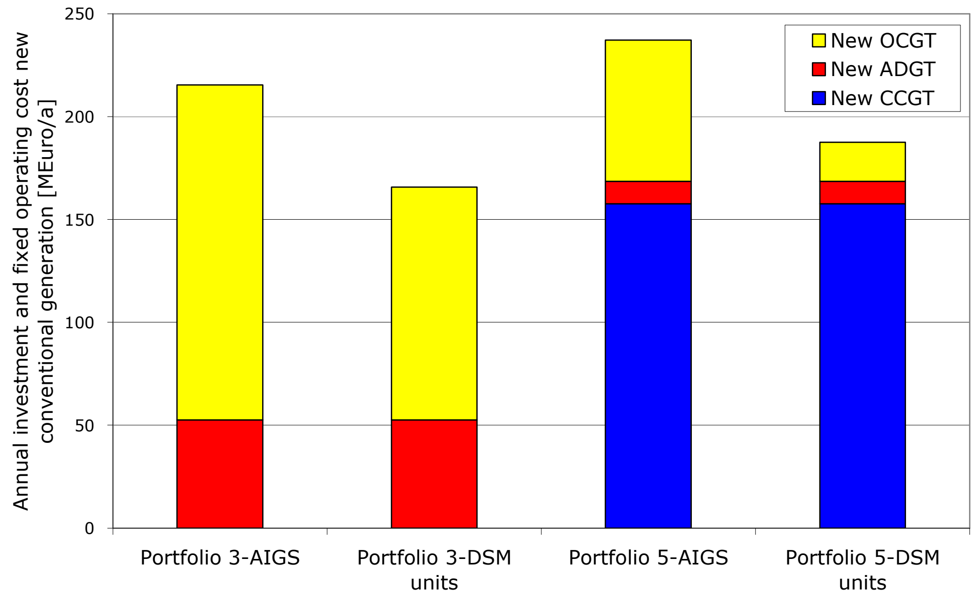


Figure 5.6: Investment annuity and annual fixed operating costs for new conventional generation

5.3.3 Dispatch of conventional and DSM units

Although all technical characteristics of conventional plants are taken into account in the system dispatch, due to the hourly resolution only one peat fired unit has restricting ramp up and ramp down rates. Hence, almost the whole operating range is utilised by all units aside from the installed wind capacity.

In Figure 5.7, the capacity factors for the defined generator groups that result from the dispatch simulations of all DSM cases of portfolios 3 and 5 are presented[13]. The following observations can be made:

- For all generation groups, the efficiency DSM measures lead to a respective reduction in the capacity factors. This reduction is spread between the units based on their respective costs and efficiencies, leading to a lower relative reduction for the cheaper coal units or the more efficient CCGTs and higher for the and higher for the gas turbines, OCGTs and ADGTs.
- The introduction of DSM units leads to a slight improvement of the capacity factors of all generation groups. This improvement is higher in the case of OCGT units which correspond to the part of the portfolio that is replaced by DSM units.
- In portfolio 3, the combined cycle, gas-based generation (CCGT) has a capacity factor in the range of 70% to 80% and can therefore be regarded as a baseload capacity. The high capacity factor results from the high efficiency of the units. In

[13] The capacity factor describes the fraction of the available time the plant is generating electricity weighted against its full capacity.

portfolio 5 the high share of renewable generation leads to their decreased capacity factor.

- Due to their low efficiency, the role of existing conventional (condensing) gas plants in the dispatch is minor. Their role in portfolio 3 is more dominant with capacity factor of 22%, in contrast to portfolio 5 where it corresponds to 3%. The efficiency measures lead to a drastic decrease in the utilisation of the units, to 10% for the central and 7% for the aggressive efficiency case for portfolio 3 and 0.6% and 0.5% respectively for portfolio 5. The DSM unit implementation leads to a slight increase of the capacity factor compared to the base case.
- The higher efficiency of the ADGT plants enables them to gain capacity factor of 38% for base case portfolio 3 and 11% for base case portfolio 5. Again, the efficiency measures lead to a drastic reduction of these capacity factors while the introduction of DSM units leads to the same capacity factors as the base case.
- The OCGT plants present low capacity factors, reflecting their use as peaking plants. Due to the efficiency measures these capacity factors are further reduced. The replacement of OCGT plants with DSM units lead to an improvement of the capacity factors and a better utilisation of the units.
- Because of their relatively low fuel costs, the capacity factor of existing coal and peat plants is high. They act as baseload units and present the lower reduction in their capacity factor in the efficiency cases. The extremely low capacity factors of the old gasoil plants reflect their role as providers of reserve capacity.

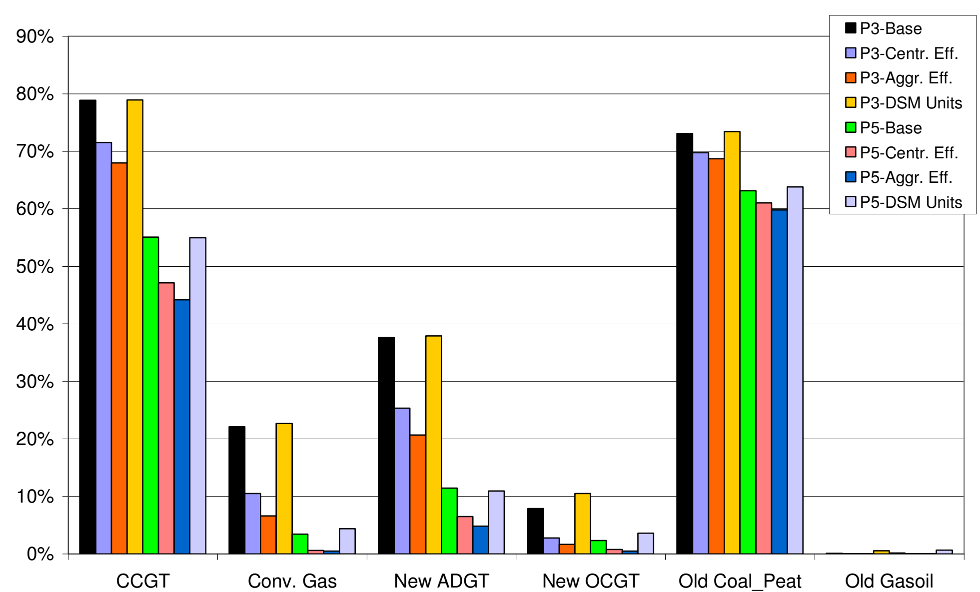


Figure 5.7: Capacity factors of conventional generators and DSM units

To further illustrate the operational behaviour of the generation groups, Figure 5.8 and Figure 5.9 show the composition of the operational modes for all DSM cases for portfolios 3 and 5 respectively. The figure illustrates that baseload units mostly deliver electricity (CCGT, existing coal and peat plants) and, hence, achieve high capacity factors. In opposite, peaking units with low capacity factors (e.g. OCGTs and ADGTs) serve one of the reserve categories during a substantial share of time, but do not generate much electricity.

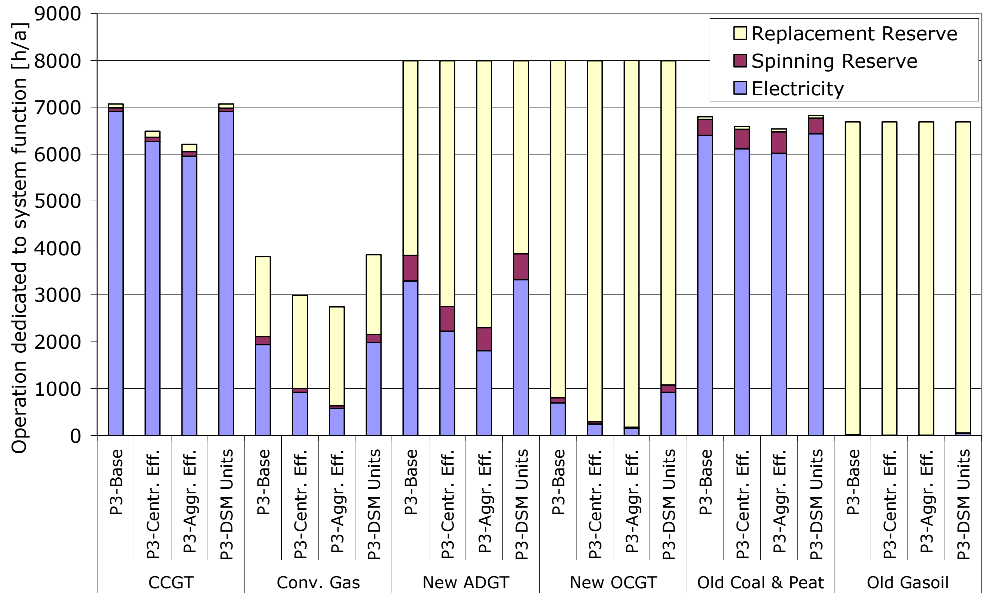


Figure 5.8: Operational modes of generation portfolio 3

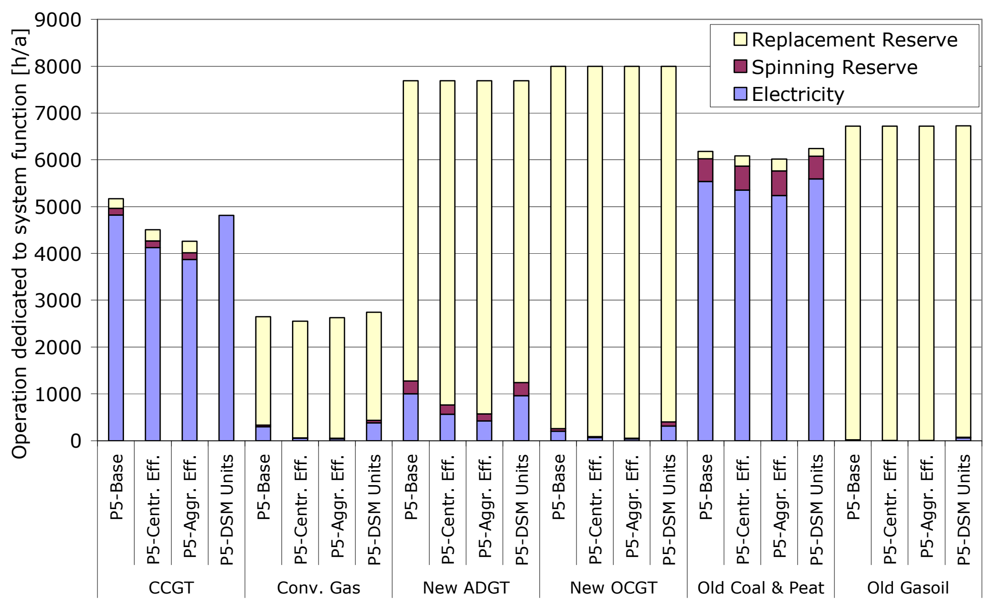


Figure 5.9: Operational modes of generation portfolio 5

For both portfolios, the efficiency measures are leading to a decrease in the electricity generation of all units. For the baseload units and the conventional gas turbines, the reserve categories are left unchanged, leading to a reduced overall utilisation of the units. In the peak units, for the time compared to the base case that the unit is not producing electricity it serves as replacement reserve, leading to the same overall utilisation.

Careful interpretation of these results is required, taking into account the assumptions and limitations of the study. The unit data applied in the dispatch model may require further elaboration and modification at detail level. Examples of those aspects are start-up time restrictions, additional O&M cost as a function of enhanced operational dynamics or extended low load operation, must run requirements, availability of the interconnector for provision of reserves etc.

Based on the system dispatch, Figure 5.10 shows the resulting total operational costs of the power system, including payments related to import and export of power to/from Great Britain divided by the total demand. The costs of CO_2 are separated from the fuel prices. The figure shows, that the efficiency measures lead to a reduction in the system operational costs per MWh without substantial change in the cost for CO_2 emissions. The cost reduction in portfolio 3 reaches up to 8% (a reduction from 37.9 to 35 €/MWh) while the reduction in portfolio 5 is as high as 10% compared to the respective base cases (a reduction from 29.2 to 26.3 €/MWh) .

The On the other hand, the cost levels chosen for the DSM units are such that the total operational costs of the system remain unchanged, while the investment costs are reduced, as shown in Figure 5.6.

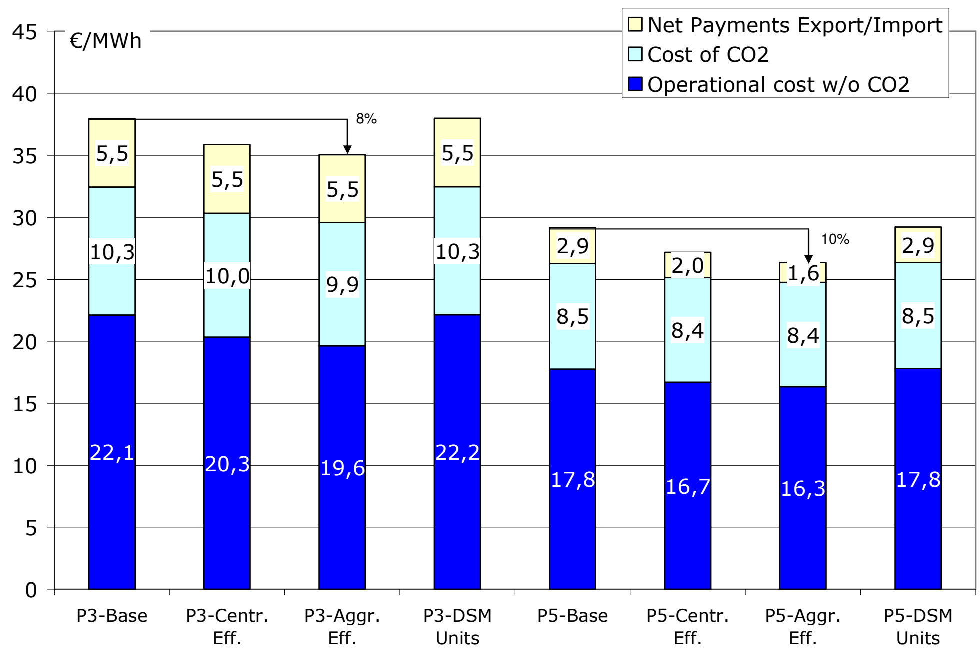


Figure 5.10: Total operational costs of power production in the All Island power system, including payments related to power exchange with Great Britain

5.3.4 Revenues of conventional generators and DSM units

The source of revenues for conventional generators, based on system marginal cost pricing can be broken down into the revenues from electricity generation and the provision of spinning and replacement reserves. The revenue breakdown is depicted in Figure 5.11. The figure shows that the applied methodology for pricing of reserves implies only marginal contributions from these services to the total revenues of conventional generators. Again, it has to be noted that, in particular the accuracy of reserve revenues is limited by methodology restrictions. What is more, within some market designs payments outside of energy payments like capacity payments are made to ensure a sufficient investment in generation capacity (generation adequacy). As no specific design was assumed in this study, such payments are not calculated. The decreasing revenues for the efficiency cases reflect the impact of the reduced system energy demand, while the increased revenues in the case of the DSM units are mainly due to the higher marginal prices of these cases, as depicted in Figure 5.11.

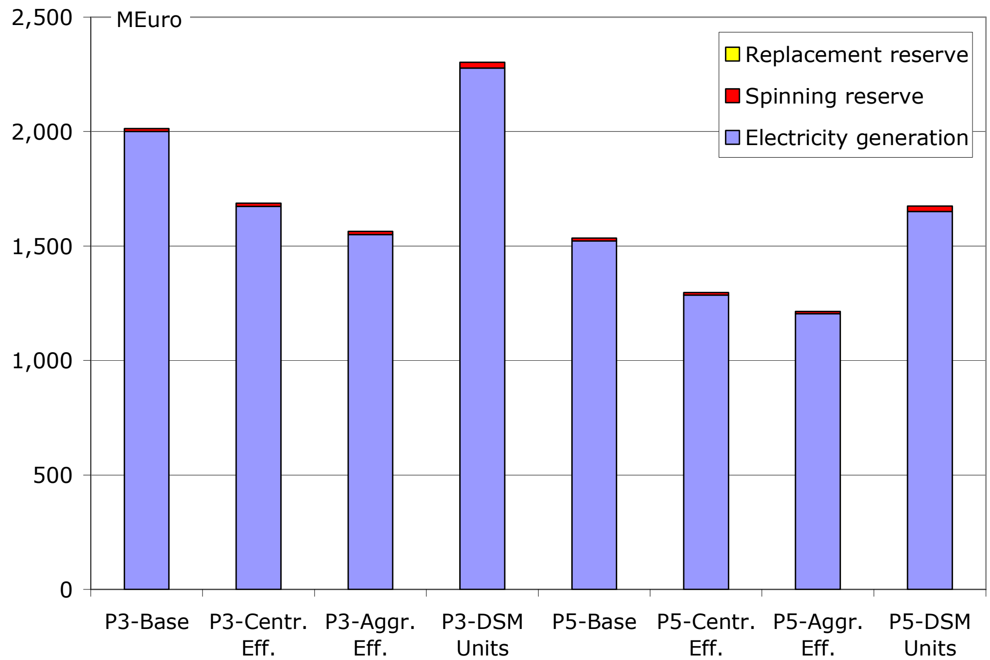


Figure 5.11: Revenue distribution of conventional generators and DSM units, excluding storage

The total generator revenues are used to cover the operating cost components (fuel-, O&M and startup-cost), investment cost and applicable network tariffs.
Figure 5.12 shows for every generation group, portfolio and DSM case, which investments could be financed from the cash flow available after operating cost components are covered[14]. In this graph a uniform annuity factor of 10.2 % was assumed that reflects an interest rate of 8 % and a plant lifetime of 20 years. It also shows the relative investment costs of conventional plants, as assumed in AIGS, to indicate where revenue adequacy issues arise. The figure should be interpreted in consideration of these simplifications and the specific market assumptions that have been made.

Figure 5.12 shows the gaps between specific capital investments that can be financed from available cash flow and the actual investment cost of new plants. It shows that in almost all cases, new plants would require additional (capacity) payments to cover the cost of the investment. Only CCGT and ADGT plants in the DSM unit case of portfolio 3 can fully cover their investment costs in the absence of such additional payments. This is mainly due to the high prices of the cases with DSM units which lead to a significant increase in the available cash flow is observed.
These results are very dependent on the operational restrictions of the system. In the original AIGS the OCGT in portfolio 5 were able to recover fixed costs, whereas the portfolio 5 base case of this study this is by far not the case. A detailed analysis of the

[14] Fixed operating costs, such as maintenance and payroll costs, (as explained in section 5.3.2) were excluded.

revenues for OCGT revealed that revenues from the provision of spinning reserve were an important source of revenue for OCGT where as in this study, spinning reserve requirements are met by other units and prices are lower.

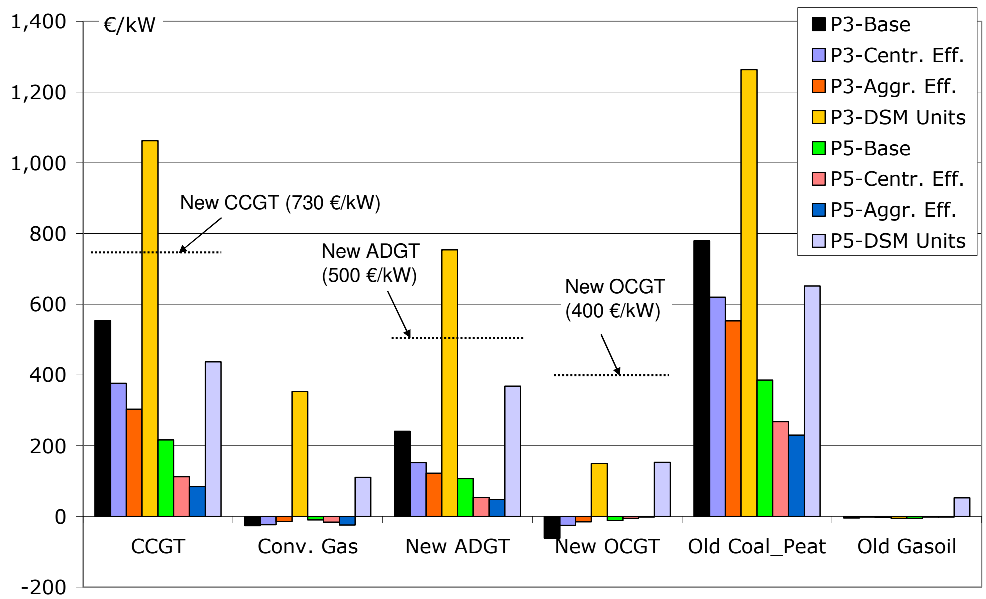


Figure 5.12: Specific capital investments in generation plants that can be financed from available cash flow and indicative investment cost for new plants

In the AIGS study the revenue gap for conventional generators has already been an important issue and it was concluded that there is scope to refine the portfolios to arrive to minimise total cost. For the portfolios and efficiency cases examined in this study, this aspect gains even more importance as the revenue gaps are increasing. This result is not surprising as this study examined portfolios were originally optimised to serve the unchanged load (high-level optimisation of workstream 2a of the original AIGS) but not optimised with respect to an optimal generation portfolio for efficiency scenarios. Hence, there is a clear requirement for the optimisation of the portfolios.

5.4 Renewable Generators

The renewable generation portfolios have not been changed compared to the AIGS. The next sections cover the dispatch of these technologies and the recovery of the investment costs.

5.4.1 Total investment volume of renewables

In Figure 5.13 the total investment volume for the AIGS portfolios as obtained by the results of the AIGS Work stream 1 are presented. Since the installed renewable capacities do not change, the same numbers apply for all DSM cases of the portfolios. The investment requirements are dominated by wind energy investments and are €6 bn and €9 bn for the portfolios 3 and 5 respectively.

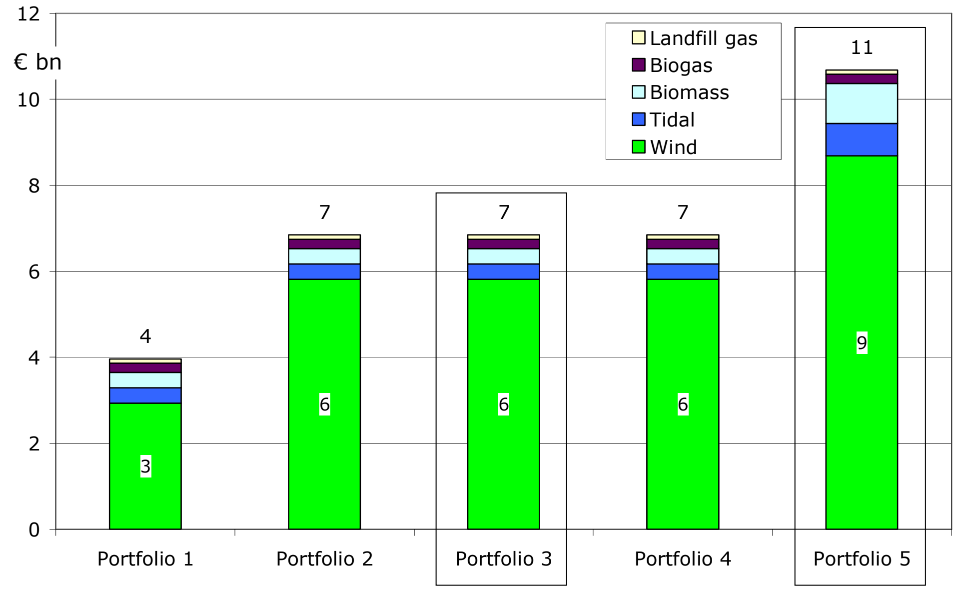


Figure 5.13: Total investment volumes in renewable energies

5.4.2 Dispatch of renewable generators

All renewable technologies with the exception of bioenergy have operational costs close to zero. Hence, the generation of variable renewable electricity is dispatched according to the given time series of electricity generation with no consideration of operational costs. Bioenergy resources ("baseload renewables") are treated as must-run units, since their variable operational costs are very low (assumed to be 10 €/MWh).

Levels and effects of wind curtailment

Curtailment of variable renewable energy is considered in two situations: as an alternative to the extension or reinforcement of the network, and to enable system balancing. Since in the current study no specific network analysis has taken place, the curtailment options are evaluated from a system operation perspective, by the inclusion of the possibility of wind curtailments in the system dispatch.

As can be seen in Figure 5.14 where the level of wind curtailment as percentage of the total wind power production is presented, for portfolio 3 the levels of curtailment are very low and hardly visible in the figure. In portfolio 5, due to the higher installed wind power capacity and the dispatch and must run requirements, this level rises but is still significantly low (0.035%). The implementation of efficiency measures lead to a reduction of the total production, which in turn leads to an increase in the levels of the *relative* curtailment. For portfolio 3, this level rises to 0.11% for the central efficiency and to

0.16% for the aggressive efficiency case. The absolute curtailment, hover does not change.

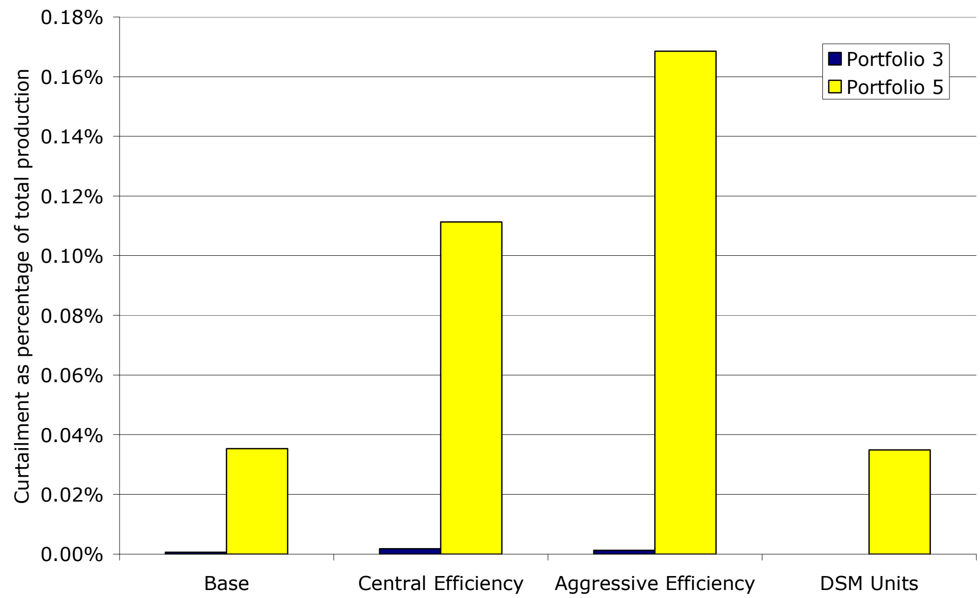


Figure 5.14: Wind curtailment for the different DSM cases for the portfolios 3 and 5

5.4.3 RES-E support requirements

This section analyses the financial position of renewable generators, both existing and new, that emerges from the dispatch simulations of the year 2020 for all the DSM cases for the two portfolios. In the dispatch simulation all renewable plants of one technology are aggregated and treated as one large plant. The annual revenues for a renewable generator are calculated on the basis of their power output multiplied by marginal electricity prices. Since these prices are generated from a cost based dispatch where no market model was assumed, they will differ from marginal electricity prices in an actual market. From these revenues, the annualised investment costs are subtracted. For bio-energy plants operational costs are also subtracted. In each case, the remainder is considered annual profit or, when a loss, annual support requirement. This methodology takes account of the correlation of the time series of electricity production with electricity prices and the influence of renewable generation on the marginal electricity (market) price.

Figure 5.15 shows the total required support payments for all DSM cases for the portfolios 3 and 5. One can see that portfolio 3 presents lower required support payments for all DSM cases, in accordance to the results of the AIGS. This effect can be attributed to the higher price levels for portfolio 3 compared to portfolio 5 (see section 5.1.3).
The efficiency measures lead to a decrease of prices and hence to an increase of the

required support. The implementation of the DSM units leads to a respective reduction. This effect can be traced back to the behavior of the system marginal prices, which ultimately affect the revenues of the renewable generators; the lower prices due to the efficiency reduction lead to a profit loss while the higher prices in the case of DSM units lead to an increased profit for the generators.

When interpreting the results illustrated in Figure 5.15, one has to reflect the ideal character of the model and its underlying methodologies. All support mechanisms incur some inefficiencies, where the support level provided to some renewable energy generators exceeds their requirements to break even. The support cost estimated by this analysis represents that which would incur if a perfectly efficient support mechanism were employed. As such it is possible that this analysis underestimates the support costs that would be incurred.

The total required support payments shown in Figure 5.15 are further disaggregated in Figure 5.16 to show the relative support requirements for the technologies for each case. This figure shows that the relative support requirements do not vary considerably for all cases except for the DSM units of the portfolio 3.

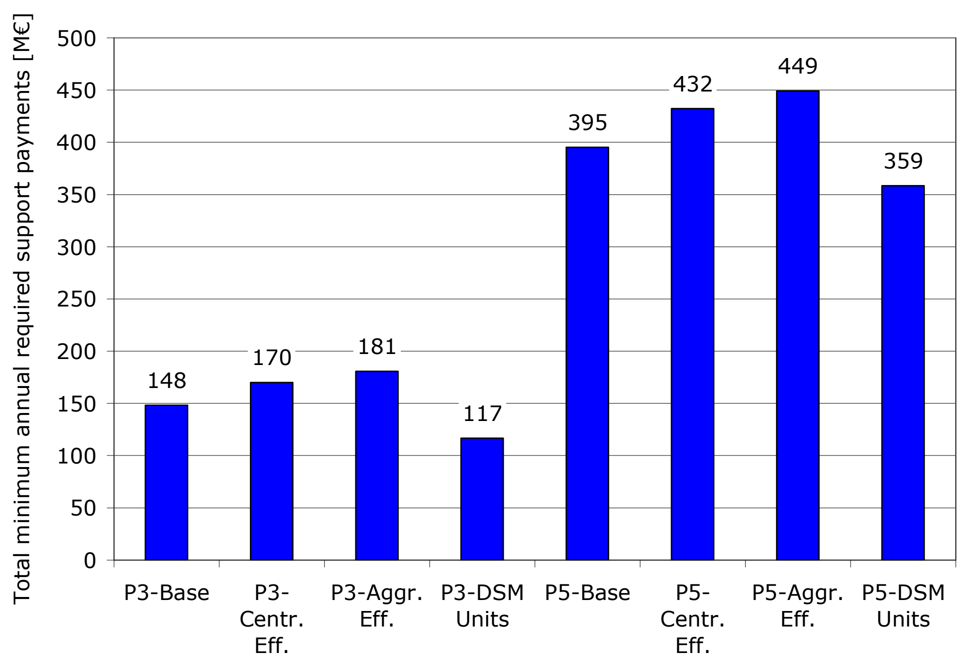


Figure 5.15: Total minimum annual required support payments assuming a perfectly efficient support mechanism

![ECOFYS]

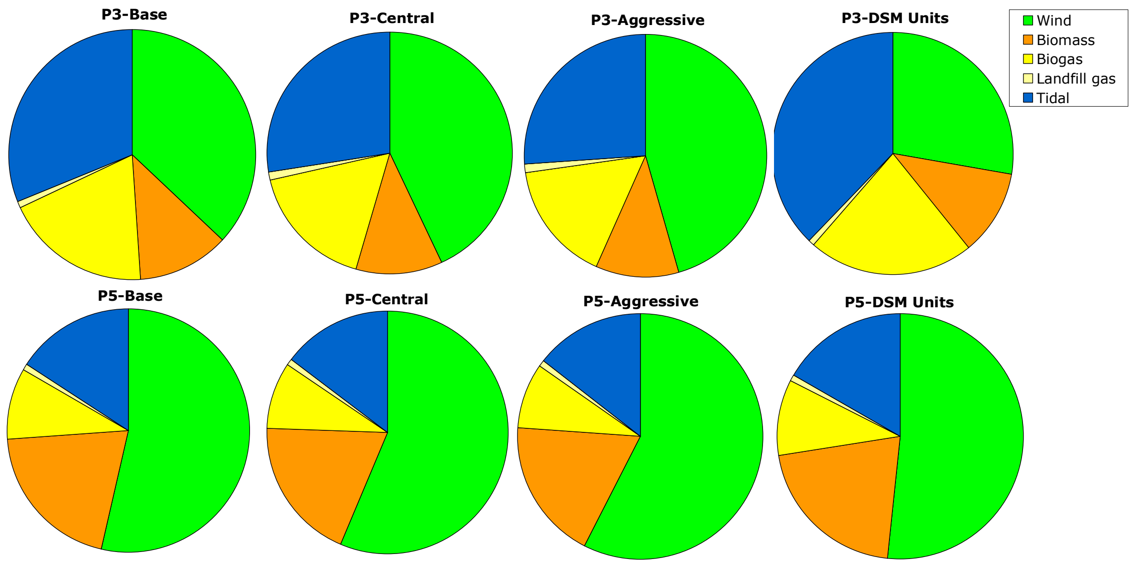


Figure 5.16: Distribution of minimum required support payments by technologies

5.5 Network operators and -owners

According to the AIGS methodology, the analysis of the impacts on network operators and owners distinguishes between issues affecting system operation of a future system, issues that affect the construction and maintenance of the transmission network and issues regarding network connections and the operation of the interconnector. The issues of construction and maintenance of the transmission network are not discussed in this study, as network implications were not included in the analysis.

5.5.1 System operation

Provision of reserves

An important aspect of reliable system operation is the availability of required reserves in generation, necessary to cope with imbalances between load and generation caused by errors in the predicted levels of loads and/or wind power output or by large power fluctuations resulting from changes in load as well as (wind) generation but also tripping of generation units. To maintain balance, the system operator needs generation capacity that is effectively immediately dispatchable.

In theory DSM units could be used for the provision of reserves. Such a DSM program is currently in operation in the Republic or Ireland (Interruptible Load/Short Term Active Response - STAR) while current DSM programs as the Economy 7 in Northern Ireland could be used for this purpose also. In the current study, this option has not been explored, since the DSM units were considered to operate only in the day-ahead market. As shown in the reliability results presented in Figure 5.2, this leads to an increase in the number of hours when reserve capacities were not met. The inclusion of DSM measures for provision of reserves would (in parallel to avoiding investments in peaking plants) ultimately lead to improved system reliability and consequently to a reduction to the system marginal costs due to the avoidance of reliability events (as shown in Figure 5.3).

5.5.2 Interconnector operation

For 2020, two interconnectors from the All Island System to the power system of Great Britain with a total capacity of 1000MW are assumed. While 100MW are reserved for the provision of spinning reserve, the remaining capacity is used to optimise both generation systems.

The pattern of the energy transports via the interconnector changes with the demand of the all island system. Figure 5.17 shows that the efficiency measures lead to an increase in the electricity exports and respective decrease of imports to the all-Island system. The implementation of DSM units brings no substantial effect to the expected annual energy flows.

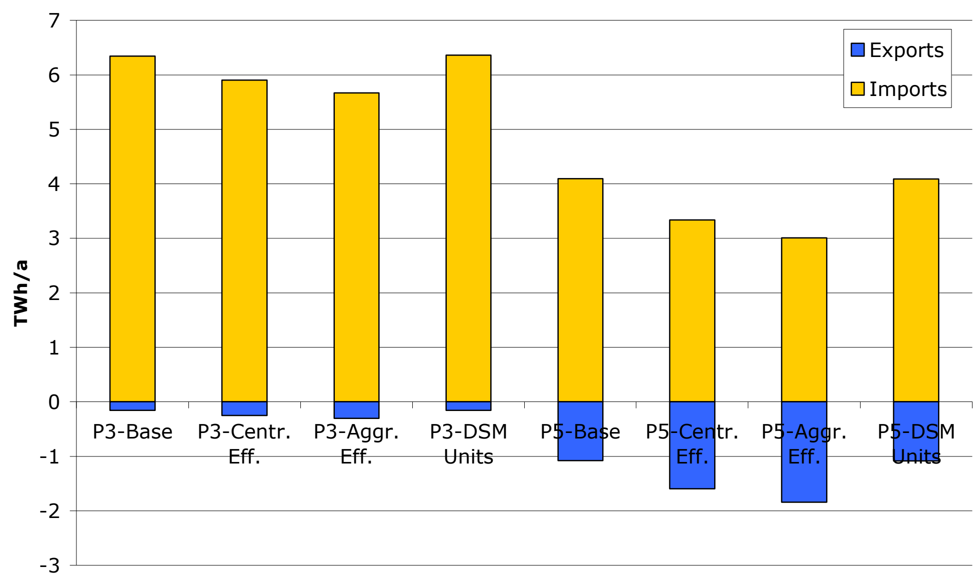


Figure 5.17: Expected annual energy flows via the interconnectors

5.6 Societal impacts and costs to end-users

Societal impacts are environmental impacts and long-term implications of the security of fuel supply.

5.6.1 Environmental impacts

CO_2 Emissions

Figure 5.18 shows the relative differences of CO_2 emissions of the portfolios as com-

pared to the original portfolio 1 of the AIGS. The green bars show the change of CO_2 Emissions in the All Island system. While the base scenario of portfolio 3 leads to a reduction of 8% relative to portfolio 1, efficiency measures increase these savings to 18% for the central efficiency case and 22% of the aggressive efficiency case. For portfolio 5, the savings are increased from 24% to 31% and 34% for the aggressive efficiency case.
These figures also allow a comparison of the impact of different climate policies on CO_2 emission: To gain about the same emissions savings assumed in portfolio 5 using portfolio 3 and efficiency measures, aggressive efficiency measures would have to be introduced.

Additionally, in all scenarios small reductions in the GB power system are achieved. Thus, emission reductions in the All Island power system are not offset by emission increases in the GB system.
For the cases examining the impact of DSM units, no additional emission savings are achieved. These units, DSM units, while CO_2 free, replace OCGTs, and increase the use of other peaking units, which are more carbon intensive. Also, load shifting will slightly increase use of coal during night hours.

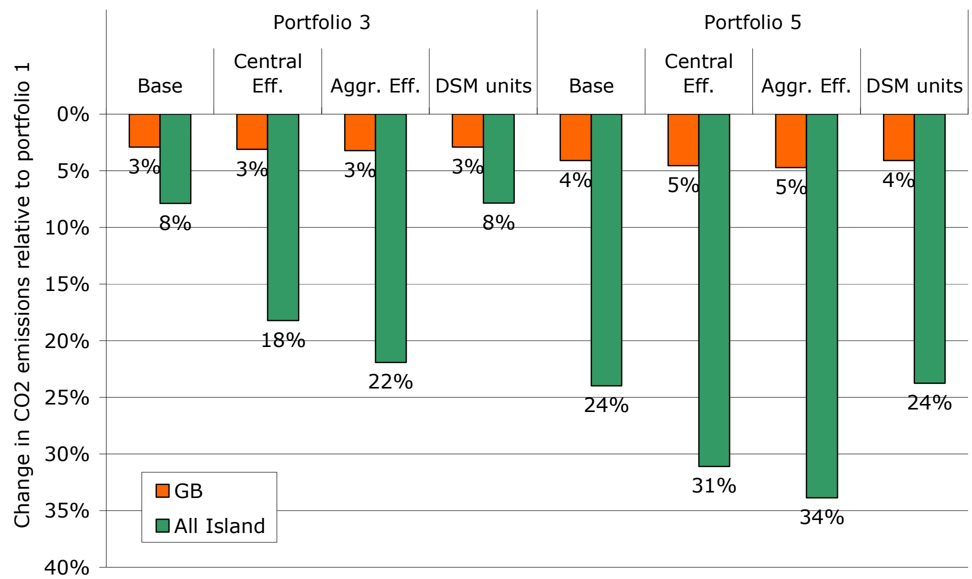
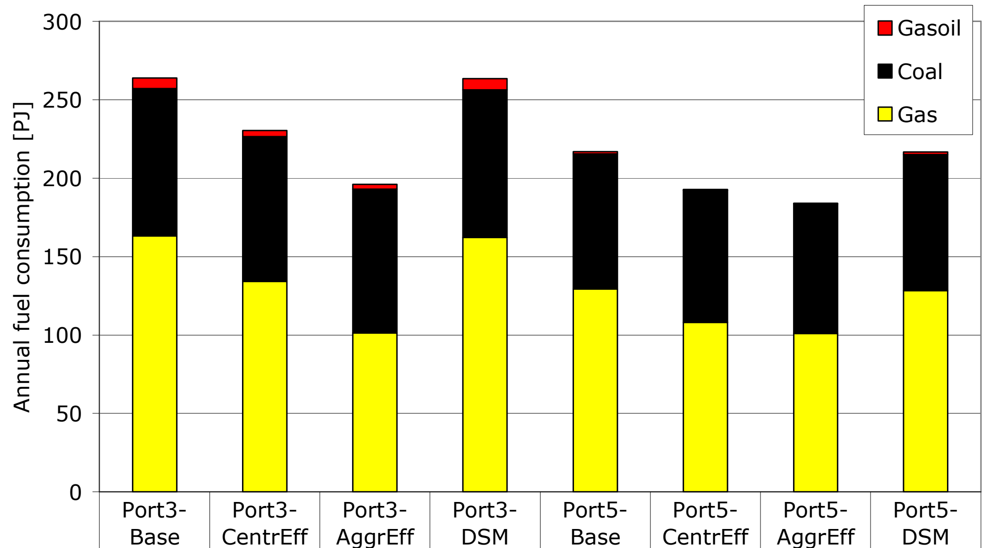


Figure 5.18: Percentage change in CO_2 emissions relative to Portfolio 1

5.6.2 Long-term security of supply

The composition of generation units in the portfolios has a significant impact on the amount of conventional fuels employed.



	Port3-Base	Port3-CentrEff	Port3-AggrEff	Port3-DSM	Port5-Base	Port5-CentrEff	Port5-AggrEff	Port5-DSM
Gasoil	7	4	3	7	1	1	0	2
Coal	94	92	92	94	86	84	83	87
Gas	163	134	101	162	129	108	101	128

Figure 5.19: Annual fuel consumption of fuels with high import shares[15]

Figure 5.19 shows the annual fuel consumption by the all island power system of those fuels that, for the most part, have to be imported. It can clearly be seen that the total amount of imported fuels declines with the implementation of efficiency measures. The main reduction takes place in the gas consumption, due to the high utilisation and increased costs related to this fuel.

As the study assumes two large electricity interconnections with the GB power system, the analysis needs to include the consideration of exports and imports to and from the all island power system. As Figure 5.17 depicts, the reduced fuel imports are not offset by increased electricity imports; rather the opposite appears to occur. This can be seen also in Figure 5.20, where the annual net electricity imports are presented.

[15] Baseload gas and Midmerit gas are aggregated

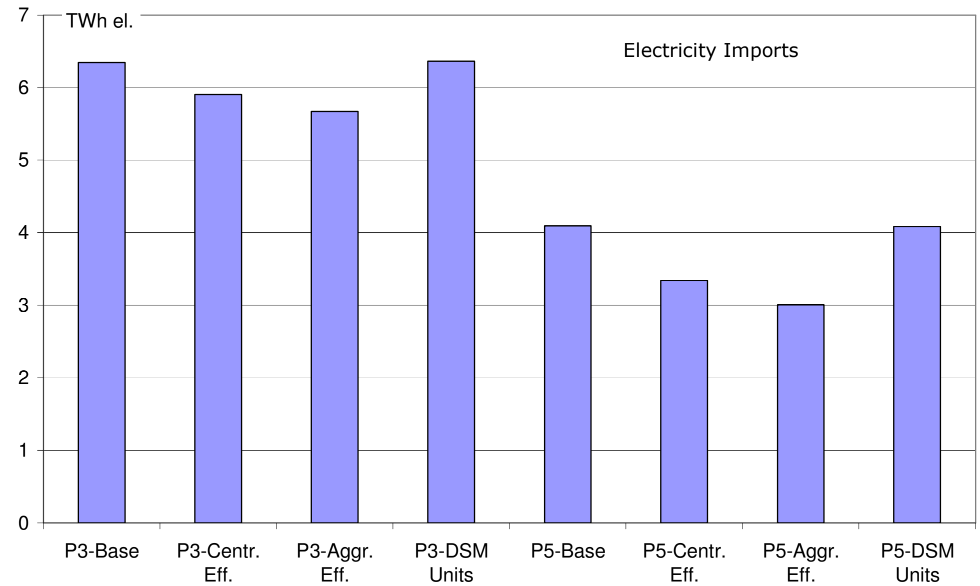


Figure 5.20: Annual net electricity imports to the all island power system

Since the gas import capacity is limited by available transmission pipelines and the capacity of terminals to handle Liquefied Natural Gas, the maximum required daily capacity is analyzed. Figure 5.21 shows that the maximum demand does not differ significantly between the portfolios. Existing variations have to be evaluated in the perspective of the snapshot character of the study. With the limited period covered by the simulation, the particular day of maximum gas import and the associated import volume per portfolio is reduced significantly for the efficiency cases, especially for the portfolio 3.

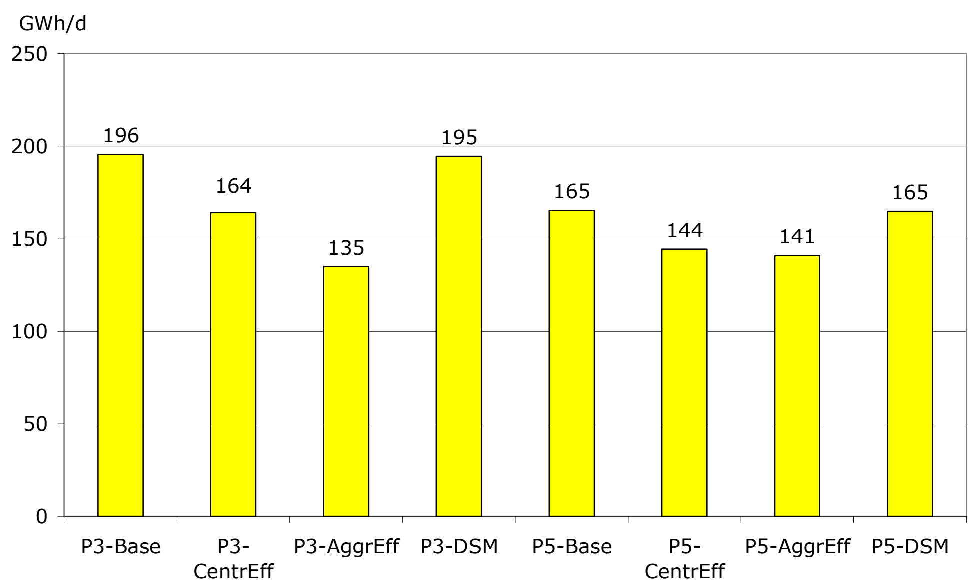


Figure 5.21: Maximum daily gas demand of the All Island system (baseloadgas and midmeritgas)

The following conclusions can be drawn with respect to long-term security of supply:

- In all examined cases the all island power system will continue to rely on net electricity imports from the GB system.
- The application of greater shares of renewable based electricity (Portfolio 5) leads to a significant decrease in the dependency on fuel imports of the all island power system. The impact of efficiency measures is of a higher relevance for portfolio 3 compared to portfolio 5 where the reliance on fossil fuels is higher. Additionally, the electricity imports from the GB system are reduced.
- The efficiency measures decrease the maximum daily gas demand. These effects are more significant in portfolio 3 compared to portfolio 5.

5.6.3 Additional costs to society

The key cost and benefit categories discussed up to this point are aggregated and illustrated in Figure 5.22 for the different DSM cases of portfolios 3 and 5. This figure depicts the annual CO_2 emissions, thus illustrating the reduction achieved in the different cases. But most of all, the figure provides an aggregation of the costs to society considered in the study in millions of euros for the year 2020 for the different cases. As discussed in the AIGS, it has to be pointed out that the given cost figures do not reflect expected electricity prices but rather indicate the relative relationship between the elements of the costs of generation investigated in this study in the different scenarios.

The additional cost to society is defined as the sum of the operating costs of the power system and varies with the cases. The costs are additional to the investment costs of existing conventional generators and existing and base case transmission asset costs. These costs include:

- The operational costs of generation consisting of the fuel costs and the cost of CO_2 , including fuel and CO_2 costs incurred in start up, as discussed in section 5.6.1 and illustrated in Figure 5.18;
- The charges for the net imports over the interconnector as discussed in section 5.5.2;
- The total annual investment costs for all renewable generation, existing and new, as identified in section 5.4.1;
- Investment in new conventional generation as described in section 5.3.2. Under market rules these costs would typically be covered by revenues from energy markets (infra marginal rents) as well as by those from ancillary services and capacity payments where in place.
- The annual investment in network reinforcements, kept at the same levels for all DSM cases for the two portfolios as in the AIGS.

The following costs were excluded from the analysis:

- the historic investment costs of existing conventional generation as well as for the existing transmission assets. As these cost components apply identically to all portfolios it does not compromise a comparison between the portfolios.
- variable maintenance costs

These additional costs will need to be recovered within the price of electricity charged to end users.

The impact of the DSM options for the two portfolios studied on the prices charged to end customers cannot be determined as the study of markets is out of scope for this study. However, this study identified differences arising in certain price components that make up the final price charged to end users on their electricity bills, the following of which are included in the analysis:

- electricity wholesale prices (section 5.1.3) and;
- support payments for renewable generators (see section 5.4.3).

The following components of the electricity price have not been included in the analysis:

- distribution charges, and
- capacity payments for generators.

As can be seen in Figure 5.22, the efficiency cases may lead to annual cost reductions of up to €381 million (portfolio 3) or €321 million (portfolio 5).

The information presented in Figure 5.23 is based on the same cost information as that used in Figure 5.22, but displays these costs in €/MWh based on annual electricity consumption of the all island system to illustrate the order of magnitude of the change of the cost components examined. It shows that the total cost differences per MWh to end users between the different DSM cases are very low. For portfolio 5, the total cost per MWh increases slightly.

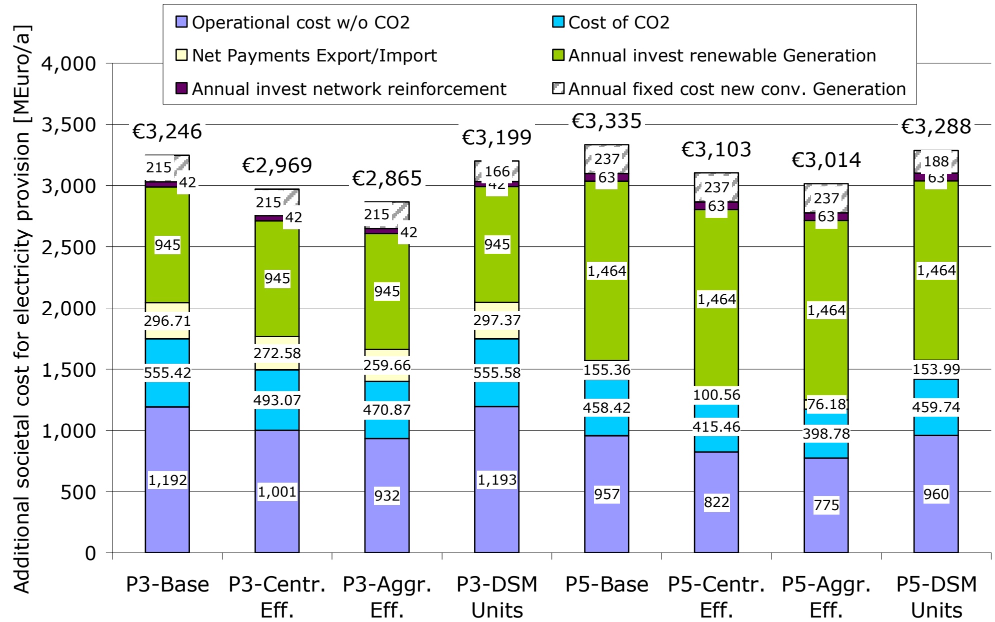


Figure 5.22: Additional societal costs for electricity provision

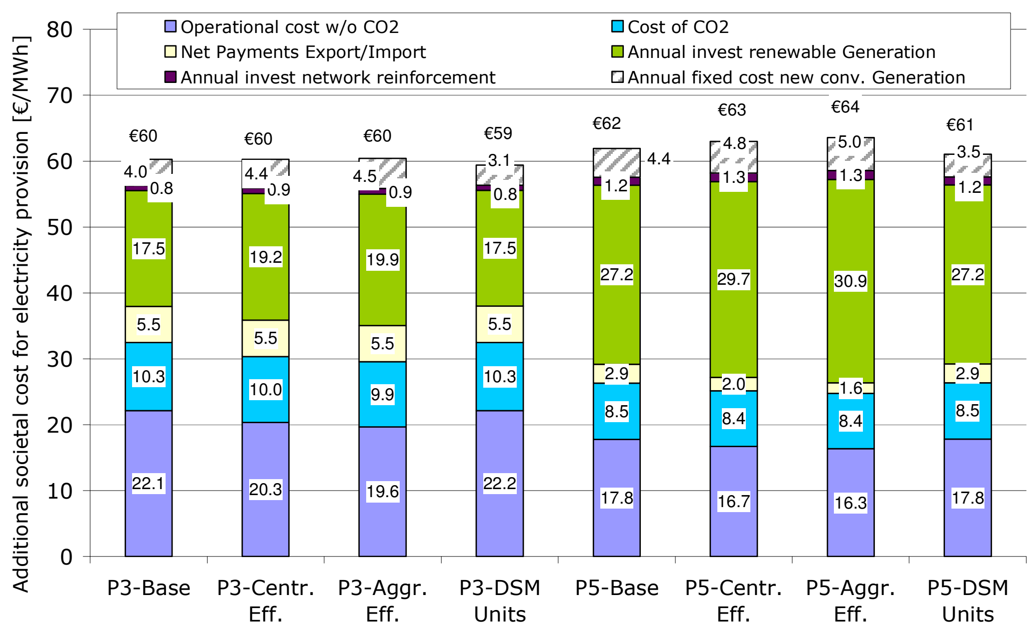


Figure 5.23: Overview of the DSM options for portfolios 3 and 5 indicating specific additional societal costs for electricity provision

However, attention has to be drawn to the fact that from the setup of the study generation portfolios have not been optimised. Reducing the number of units within a further optimisation of portfolios could possibly reduce the annual fixed investment cost for conventional generation.

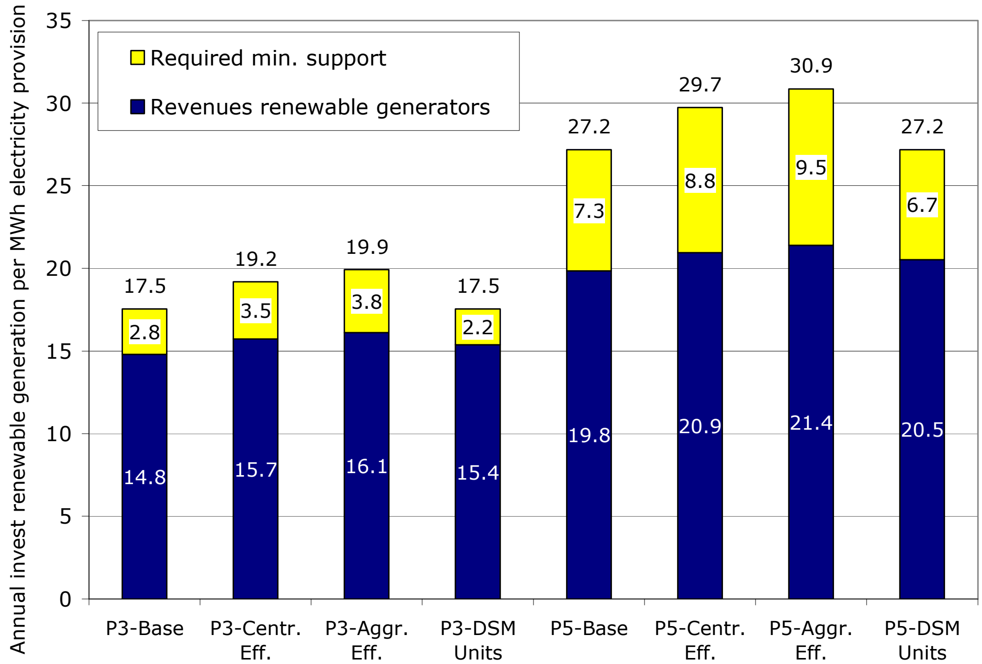


Figure 5.24: Financing of the investment cost for renewable generators

Figure 5.24 includes a breakdown of annual investment costs for renewable generation by costs covered by revenue and costs requiring a support mechanism. The revenue share depends on the electricity price level in the respective DSM case and portfolio (see Figure 5.3). It becomes obvious, that a great share of the required investment cost can be recovered from revenues on the electricity market as part of the electricity wholesale prices. This is due to the fact that the levelised cost of renewable generation is in many cases close to the cost of conventional generation.

It was explained in section 5.3.4 that within the assumed methodology conventional generation also requires payments additional to system marginal costs. The calculation of those payments is clearly outside the scope of this study. Depending on the electricity market design renewable generators may be able to benefit from those payments as well. This applies especially for firm renewable baseload capacity such as biomass plants. Hence, required support payments can be further reduced.

On the other hand, the study assumed an ideal support mechanism without windfall profits arising to renewable generators as explained in section 5.4.3. In reality, support mechanisms can over compensate relative to costs incurred. Both of the above effects have an impact on the required share of support, the impacts being in opposing directions.

Given the above mentioned limitations of the analysis it can be seen that the order of magnitude of additional support for renewables ranges between €2.2 and €3.8 /MWh for portfolio 3 and between €6.7 and €9.5 /MWh for portfolio 5. The efficiency measures bring a need for higher support due to the decrease in the electricity prices while the introduction of DSM units leads to a reduction of the required support due to the respective increase in prices.

6 Summary and conclusions

In this study, the system costs and benefits from the implementation of two types of DSM measures to portfolios studied in the AIGS were investigated:

1. *Efficiency measures* that lead to energy savings and consequently to a reduction of the system electricity demand. These measures were incorporated in the analysis based on the results of the KEMA study.
2. *Flexibility measures* that lead to a substitution of peaking units in the respective portfolios with DSM units. Such measures were not investigated in the KEMA study. The operation of the DSM units was defined based on interviews with the main stakeholders and according to the results of a sensitivity analysis, so that the total system costs are kept constant (Figure 5.10).

With respect to the implementation of DSM efficiency measures to the generation scenarios of portfolio 3 and 5 the following observations were made:

- Efficiency measures increase the reliability of the system as an additional generation is available and can almost always provide sufficient replacement reserve.
- When system load decreases due to efficiency measures, wind curtailment increases. However, this applies only for portfolio 5 and the maximum curtailment is still relatively low (0.16 % of total wind production).
- The system marginal prices will decrease with increasing efficiency and a given generation portfolio. The relative reduction is higher for portfolio 5. Price volatility will also be decreased.
- If the generation portfolios remain constant conventional units will experience lower capacity factors. This will lead to an increased gap of realised and required revenues for conventional generators to finance their capital cost.
- Decreasing electricity prices will also lead to increased RE support requirements.
- Efficiency measures will decrease imports from the GB system.
- Efficiency measures can help to decrease CO_2 emissions. The reduction achieved with efficiency measures in portfolio 3 is almost as high as the reduction achieved due to the addition of 2000MW of wind in portfolio 5 without efficiency measures.
- A positive effect on the long-term security of supply can also be noted.

The implementation of DSM flexibility measures leads to the following impacts:

- The introduction of DSM units can lead to a reduction in the system investment costs.
- If DSM units are integrated in the system to replace peak plants, it has to be ensured that these units are ready to provide spinning and replacement reserve. Otherwise, the reliability of the system will decrease.
- The integration of dispatchable DSM units might lead to higher prices if the reliability of the system is degraded.
- If DSM units are integrated in the central dispatch, their variable costs must be considerably lower than the payments currently in place with existing DSM schemes. The achieved system benefits may be distributed to the DSM units via a different payment mechanism, e.g. as capacity payments.

With respect to the total additional societal costs for electricity provision, efficiency DSM measures may lead to annual cost savings of €382 million (portfolio 3) or €321 million (portfolio 5). The specific additional costs for each MWh produced remain constant for portfolio 3 and increase slightly for portfolio 5. Hence obviously the marginal benefits of DSM efficiency measures are decreasing. The introduction of DSM units leads to a slight decrease of overall costs, but it has to be considered that the operational costs assumed are most likely not sufficient to mobilise the resource.

A further optimisation of the portfolios is recommended to evaluate an optimal mix of the various generation technologies and DSM units. DSM units have to be further specified with respect to their ability to provide spinning reserve. By conducting a further optimisation, of the portfolios it appears likely, that a cost reduction of the specific MWh produced can be achieved as a additional benefit additional to the CO_2 reductions.

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