Project no.:
608540

Project acronym:
GARPUR

Project full title:
Generally Accepted Reliability Principle with Uncertainty modelling and through probabilistic Risk assessment

Collaborative project

FP7-ENERGY-2013-1

Start date of project: 2013-09-01
Duration: 4 years

D3.2
Recommendations for implementing the socio-economic impact assessment methodology over the pan-European system in a tractable way

Due delivery date: 2016-08-31
Actual delivery date: 2016-09-12

Organisation name of lead beneficiary for this deliverable:
Háskólinn í Reykjavík [RU]

Project co-funded by the European Commission within the Seventh Framework Programme (2007-2013)		
Dissemination Level		
PU	Public	X
PP	Restricted to other programme participants (including the Commission Services)	
RE	Restricted to a group specified by the consortium (including the Commission Services)	
CO	Confidential , only for members of the consortium (including the Commission Services)	

Deliverable number:	D3.2
Deliverable short title:	Recommendations for implementing the socio-economic impact assessment methodology
Deliverable title:	Recommendations for implementing the socio-economic impact assessment methodology over the pan-European system in a tractable way
Work package:	WP3 Socio-economic assessment of reliability criteria
Lead participant:	RU

Revision Control			
Date	Revision	Author(s)	Comments

Quality Assurance, status of deliverable		
Action	Performed by	Date
Verified (WP leader)	Fridrik Mar Baldursson (RU)	2016-09-12
Reviewed (Sc. Advisor)	Louis Wehenkel (ULg)	2016-09-12
Approved (EB)	EB22 meeting in Brussels	2016-10-18
Approved (Coordinator)	Oddbjørn Gjerde (SINTEF)	2016-10-24

Submitted		
Author(s) Name	Organisation	E-mail
Fridrik Mar Baldursson	RU	fmb@ru.is
Julia Bellenbaum	UDE	Julia.Bellenbaum@uni-due.de
Marten Ovaere	KUL	Marten.Ovaere@kuleuven.be
Ewa Lazarczyk	RU	ewalazarczyk@ru.is
Gerd Kjølle	SINTEF	Gerd.Kjolle@sintef.no
Efthymios Karangelos	ULg	e.karangelos@ulg.ac.be
Christoph Weber	UDE	Christoph.Weber@uni-due.de
Stef Proost	KUL	Stef.Proost@kuleuven.be

Table of Contents

Page

The research leading to these results has received funding from the European Union
Seventh Framework Programme under Grant Agreement No 608540.

Table of Figures

Page

Table of Tables

Page

The research leading to these results has received funding from the European Union Seventh Framework Programme under Grant Agreement No 608540.

EXECUTIVE SUMMARY

This report provides recommendations for implementing the socio-economic impact assessment (SEIA) methodology developed within GARPUR. The methodology is intended to be used for comparing economic outcomes resulting from different reliability management approaches and criteria (RMACs). The SEIA methodology is based on social welfare analysis of the electricity market and allows to quantify the costs, benefits, and surplus of all market stakeholder groups: electricity consumers, electricity producers, the TSO and the government, and environmental surplus from externalities. The calculation of surplus on a stakeholder level requires an assessment of all flows of goods (e.g. fuel, electricity) and services (e.g. flexibility, transmission) and the corresponding flows of money. Three findings are of importance. First, the internal flows – also referred to as transfers – require a detailed account of market regulations and agreements between stakeholders. Second, internal flows cancel out when adding up all stakeholders' surpluses and are thus irrelevant for the SEIA from the system perspective. Third, one should avoid double counting – i.e. considering an item twice or multiple times.

The SEIA methodology is also formulated for multiple time horizons. Since decisions taken at one point in time may have implications later, costs and benefits should be either calculated as net present values (NPV) or should be annualised for intertemporal assessment.

In a situation where several countries, regions and TSOs, or multiple consumer groups, are to be considered, the SEIA may be modified. We show that cross-border cooperation increases surplus and that flows crossing borders to other regions have to be included in the expression of regional surplus. Furthermore, the SEIA shows that reliability criteria have distributional effects on different consumer groups and different locations. Changing the reliability criterion will come at a cost for some consumers and as an advantage for others. Therefore, its acceptability may differ. A change leads to two fundamental trade-offs. First, economic efficiency versus equity. Imposing limits on inequality, e.g., a minimum or universal reliability level, not raising costs of high-cost consumers, decreases efficiency but is generally considered to be more fair. Second, individualism versus solidarity. That is, does every consumer pay for the cost he imposes on the system or are costs socialised. Striking the balance between these opposing objectives is the role of a regulator, based on society's preferences.

Next, the report considers data requirements and data availability. In general, the SEIA requires quantity inputs, such as energy not supplied, TSO actions taken, generation fuel input, and corresponding value inputs (value of lost load, cost of actions, per unit fuel cost). The value of lost load is a central value in the socio-economic analysis. Due to the fact that it is usually much higher – typically by two orders of magnitude – than the electricity price, it can impact an assessment despite low quantities of energy not supplied. Data availability is also a concern. Quantity data come from simulations using the GARPUR quantification platform, which is a simulation tool developed within the GARPUR project that allows for the comparison of reliability management criteria with respect to social welfare, while value inputs will typically need to be procured from various sources (e.g. cost data from TSOs, electricity prices, studies estimating costs due to electricity interruptions (value of lost load (VOLL))), fuel prices, regulation, environmental damage estimation studies). An important point is that missing VOLL data can be substituted by data from similar countries, if the correct normalization factor and purchasing power parity are used.

Finally, the report presents a roadmap for further development. First, the SEIA framework can be extended in order to analyse possible responses of electricity market stakeholders to changing market variables. Ideally, electricity market prices and power system volumes (quantities) would be determined simultaneously in a single module with interaction between the two types of variables. Second, future research also needs to be directed towards the building blocks of electricity market models, in particular

The research leading to these results has received funding from the European Union
Seventh Framework Programme under Grant Agreement No 608540.

the estimation of consumer response to price and reliability. Third, availability of data required to perform SEIA is a necessary condition. Last, full adoption of the SEIA methodology would come through its inclusion into handbooks and guidelines for TSOs.

The research leading to these results has received funding from the European Union Seventh Framework Programme under Grant Agreement No 608540.

1 INTRODUCTION

This document is the second deliverable of work package 3 (WP3) of the GARPUR[1] project. The GARPUR project designs, develops and assesses new probabilistic reliability criteria for the electricity transmission network and evaluates their practical use while maximising social welfare. WP3 of the GARPUR project develops a sound methodology for the quantitative evaluation of the socio-economic impact of different reliability management approaches [1].

The first deliverable from WP3 [2] formulated and illustrated the socio-economic impact assessment (SEIA) methodology with and without market response. This deliverable provides a more concrete implementation of that methodology, where the practical limitations of the methods proposed in [2] are taken into account. This implementation can be applied in later workpackages of the GARPUR project, and also in other studies of the electricity market where reliability of electricity supply plays a key role. The report also identifies key methodological issues in socio-economic impact assessment relating to reliability and outlines a roadmap for further development of these methods.

Following this introduction (Chapter 1), Chapter 2 provides an overview of key terms and definitions as well as a list of mathematical variables used in the remainder of the report.

In Chapter 3, key methodological issues in socio-economic impact assessment of reliability criteria are identified. In particular, the analytical approach to SEIA, developed in [2], is summarised and an accounting framework for social surplus, which is the key economic measure of impact is presented. To identify sectoral impacts it is also important to account for sectoral surpluses which for each economic stakeholder are quantified as the difference between benefits and costs. As a whole, the sectoral surpluses sum up to social surplus. The sectors considered are as follows:

- Electricity consumers: consumer surplus is defined as consumer benefit less interruption costs, electricity payment – a transfer to producers, transmission tariff payments – a transfer to the TSO, plus other transfers, such as interruption compensation, demand-response payments, value-added taxes (VAT), DSO tariffs, etc. The framework specifies how to assess interruption costs – depending on data availability – as a function of consumer type, location, time and duration of interruption and whether or not the interruption was notified in advance.
- Electricity producers: producer surplus is defined as electricity payments less costs of fuel, investment, operation and maintenance and costs related to the environment plus other transfers such as environmental taxes and congestion payments.
- Transmission system operator (TSO): TSO surplus is defined as transmission tariff payments less monetized electricity losses, costs of operation, maintenance and investment – including costs related to land use and environmental impact – plus other transfers such as congestion payments.
- Government: Government surplus is defined as revenues from value-added tax on electricity consumption.
- The environment (represented by society as a whole): environmental surplus is the negative of monetized environmental costs of emissions resulting from the production of electricity. In order to avoid double counting, for costs that are already internalised in the generation costs – e.g. costs of CO2 emission permits within the EU Emissions Trading System – only the remaining societal environmental damage should be included.

[1] http://www.garpur-project.eu/

The research leading to these results has received funding from the European Union
Seventh Framework Programme under Grant Agreement No 608540.

The formulas for individual sectors may have to be modified slightly to adapt the framework to individual cases. For example, depending on regulation of the electricity market, feed-in tariffs may be included as a class of transfers; direct compensation to consumers for interruptions is another class of transfers that may be taken into account, depending on the regulation.

Chapter 3 also treats several issues that need to be considered in the SEIA: aspects relating to what time horizon or type of decision – ranging from real-time operating decisions to long-term system development decisions – is being considered; issues relating to SEIA involving multiple consumer groups; and aspects of the SEIA arising in the analysis of multiple countries and regions.

Chapter 4 describes the implementation of SEIA in detail for each activity category, or timeframe, specified in the GARPUR approach, *viz.* operational planning and system operation, asset management and system development. The implementation takes into account that there may be several regions under consideration in the SEIA, whose social surplus as a whole is the main economic measure of impact. In section 4.1 full mathematical formulas are provided for social surplus as a whole and social and sectoral surplus in each region. It is, however, important to note that the formulas may need to be adapted to the particular case under consideration. In particular, differences in regulation of the electricity market, taxation and environmental fees (prices of emission permits or taxes imposed on emissions) and interruption costs (value of lost load) need to be taken into account in the final implementation. Furthermore, data requirements for a SEIA are considered, and input (data and parameters) collection issues for TSOs as they prepare the execution of a SEIA.

The deliverable concludes with Chapter 5, which outlines a roadmap for further development of the proposed methods and framework developed in the GARPUR project.

Appendix 1 of the report provides some conceptual context for the proposed implementation by placing the system-development part of the GARPUR SEIA in context of the ENTSO-E Guideline for Cost-Benefit Analysis of Grid Development Projects and differences between the two approaches are identified.

The research leading to these results has received funding from the European Union
Seventh Framework Programme under Grant Agreement No 608540.

2 TERMS, DEFINITIONS AND NOTATION

2.1 Terms and definitions of key concepts

Asset management
Systematic and coordinated activities and practices through which an organization optimally manages its physical assets and their associated performance, risks and expenditures over their lifecycles for the purpose of achieving its organizational strategic plan. [3]

Congestion cost
Congestion costs are the additional generation costs when transmission constraints are present in the transmission grid. That is, the difference in generation costs between a system of infinite capacity and an actual system. In order to alleviate congestion, cheap generation in an export-constrained node should decrease, while more expensive generation in an import-constrained node should increase [25].

Contingency
A contingency is the unexpected failure or outage of a system component, such as a generator, transmission line, circuit breaker, switch, or other electrical element. A contingency may also include multiple components, which are related by situations leading to simultaneous component outages [4].

Energy not supplied
Energy not supplied is the estimated energy which would have been supplied to end-users if no interruption had occurred [29].

Expected value
The expected value of a random variable is the long-run average value, calculated as the probability-weighted average of all possible values.

N-1 criterion
The N-1 criterion is a principle according to which the system should be able to withstand at all times a credible contingency – i.e., unexpected failure or outage of a system component (such as a line, transformer, or generator) – in such a way that the system is capable of accommodating the new operational situation without violating operational security limits. (The definition is partly based on ENTSO-E documents [4] and [5]).

Operational planning
Operational planning is the group of reliability management activities linked to system optimization occurring ahead of real-time operation, within the short-term and mid-term horizons. [3]

Power system reliability
Power system reliability is the probability that an electric power system can perform a required function under given conditions for a given time interval. Reliability quantifies the ability of an electric power system to supply adequate electric service on a nearly continuous basis with few interruptions over an extended period of time. ([6], IEV ref 617-01-01).

Real-time operation
Real-time operation is exercised within recurring time intervals, beginning with a regular update on the system operating conditions. The duration of these intervals (typically in the range of 15–60 minutes) is such that the system operating conditions can be assumed to be relatively predictable, unless a contingency happens. Real-time operation includes preventive, corrective and emergency operation [3].

The research leading to these results has received funding from the European Union
Seventh Framework Programme under Grant Agreement No 608540.

Reliability criterion
A reliability criterion is a principle imposing a basis to determine whether or not the reliability level of a power system is acceptable. Such a principle can be expressed as a set of constraints that must be satisfied by the decisions taken by a TSO [21].

Reliability management
Power system reliability management means to take a sequence of decisions under uncertainty. It aims at meeting a reliability criterion, while minimising the socio-economic costs of doing so [21].

Socio-economic surplus
Socio-economic surplus is the sum of surplus or utility of all stakeholders, including external costs and benefits (e.g. environmental costs).

Socio-economic welfare
While surplus is the additional aggregate utility from the existence of one market (e.g. the electricity market), welfare has a broader scope, namely the aggregate utility from all existent markets.

A change in surplus resulting from a policy change in one market is an approximation of the aggregate gain in welfare. A change in surplus in a particular market is only equivalent to a change in overall welfare under the following conditions: policy changes do mainly affect one market and consumers' utility is assumed to be quasi-linear in the good at focus (no income effects in the demand of that good). Since all markets are at least slightly interdependent, a surplus calculation in a particular market is only an approximation of a full social welfare analysis.

System development
System development deals with taking decisions that change the system's power transfer capability through construction, upgrading, replacement, retrofitting or decommissioning of assets [2].

Transmission system
Transmission system means the electric power network used to transmit electric power over long distances within and between member states. The transmission system is usually operated at the 220 kV and above for AC or HVDC, but may also include lower voltages ([7], p. 252).

Transmission system operator
A transmission system operator (TSO) is a natural or legal person responsible for operating, ensuring the maintenance of and, if necessary, developing the transmission system in a given area and, where applicable, its interconnections with other systems, and for ensuring the long-term ability of the system to meet reasonable demands for the transmission of electricity. [3]

Value of lost load
Value of lost load (VOLL) is defined as a measure of the cost of unserved energy (the energy that would have been supplied if there had been no outage) for consumers. It is generally normalised in €/kWh ([8], p. 55).

The research leading to these results has received funding from the European Union
Seventh Framework Programme under Grant Agreement No 608540.

2.2 Notation

S	Socio-economic surplus (€)
D	Consumer demand for electricity (MWh)
v	Value of served load, monetary units per quantity units (€/MWh)
c_{INT}	Interruption costs, monetary units (€)
c_{TSO}	Short-term costs of TSO (€)
C_{TSO}	Fixed costs of TSO (€)
c_{GEN}	Variable costs of electricity producers ($€/MWh$)
C_{GEN}	Fixed costs of electricity producers (€)
u	Quantity of energy not supplied (MWh)
c_{ENV}	Environmental costs resulting from the electricity market (€/MWh)
i, j	Indices for nodes
c	Index for consumer type
V	Value of lost load (€/MWh)
d	Index for duration of interruption
M	Indicator for time of interruption
n	Indicator for advance notification of interruption
c_p	Costs from emissions of a pollutant (€/MWh)
e_p	Emissions of a pollutant (ton/MWh)
d_p	Monetised environmental damage per unit from emissions of a pollutant (€/ton)
t_p	Price/tax on emissions of a pollutant (€/ton)
A	Cost parameter for TSO cost function in illustrative model of chapter 3.4 (€/MWh)
ρ	Proportion of electricity demand supplied in illustrative model
H, L	Indices for high/low cost regions in illustrative model
TC	Consumers' "total costs" in illustrative model: $C_{TSO} + TT$ (€)
AC	Average total cost of TSO in illustrative model (€/MWh)
r	Index for region
R	Set of regions
DF	Discount factor
TS	Length of time step
t	Number of time period
f	Scaling factor for value of lost load
y	Quantity of electricity generation (MWh)
p	Price of electricity (€/MWh)
l	Quantity of electricity transmitted (across borders of price areas, MWh)
I_r	Set of nodes in region r
g	Index for generation technology
G	Set of generation technologies
p	Index for pollutant type
P	Set of pollutant types
R	Compensation paid to consumers for energy not supplied (€)
x	Tax on electricity sales (%)
TT	Transmission tariff (€/MWh)
f	Fee paid by TSO to electricity producers for ancillary services
a_{ij}	Direct TSO costs of asset management on the line between nodes i and j (€)
J_i	Set of neighbouring nodes of node i
sd	Cost of system development (€)

The research leading to these results has received funding from the European Union
Seventh Framework Programme under Grant Agreement No 608540.

3 SOCIO-ECONOMIC IMPACT ASSESSMENT - KEY METHODOLOGICAL ISSUES

This chapter identifies some key methodological issues that need to be taken into consideration when a socio-economic impact assessment (SEIA) is performed. First, in section 3.1, the analytical basis for the SEIA is provided. Second, in section 3.2, an accounting framework is presented. Third, in section 3.3, some issues relating to multiple time horizons are considered. The last two sections, 3.4 and 3.5, consider multiple consumer groups and multiple countries/regions, respectively, in the context of a SEIA.

3.1 The socioeconomic impact assessment

Within the GARPUR project, the objective is to study the impact for different reliability-related TSO decisions in multiple decision-making contexts. The Socio-Economic Impact Assessment focuses on socio-economic surplus as the key economic measure of impact. The SEIA quantifies surplus as the difference between benefits and costs for all economic agents or stakeholders. In order to carry out the assessment, one has to define the system under study and its boundaries. A system is defined by four attributes:

1. The **assessed market**. In the GARPUR project we only study the electricity market. The implicit assumption of this partial equilibrium approach is that changes in the assessed market, i.e. the electricity market, do not have a significant effect on other markets.

2. The **included stakeholder groups**. In the remainder of this document we only assess the socio-economic surplus of electricity consumers, electricity producers, the Transmission System Operator (TSO), the government surplus from taxes on electricity and the environmental surplus from electricity-related externalities. Surpluses of other electricity market stakeholders, e.g. DSOs and market operators, are not assessed. This is based on the assumption that these do not change significantly with the TSO decisions studied in this document and within the GARPUR framework.

3. The **geographical scope**. TSO decisions within a certain area can influence surpluses of stakeholders in other areas. Therefore, in order to assess total surplus from a TSO decision, all areas which are significantly affected by the decisions of a TSO, in terms of impact on surplus, should be included in the SEIA.

4. The **temporal scope**. Costs and benefits are calculated for a defined period of analysis and time step. The choice of the underlying period and time step should be aligned with the object of investigation and the time horizon for which the SEIA is conducted. For example, an analysis of a system-operation action suggests a period of analysis of a couple of hours with a small time step (1 hour, 30 minutes, 15 minutes, or less, depending on the specific decision) while the period of analysis of a long-term investment is longer.

   Table 3.1 summarizes the choice of attributes of the SEIA. Environmental implications are taken into account by including society at large as a stakeholder group representing environmental interests.

The research leading to these results has received funding from the European Union Seventh Framework Programme under Grant Agreement No 608540.

Table 3.1 The four attributes of the SEIA

Assessed market	Stakeholder groups	Geographical scope	Temporal scope
Electricity market	Electricity consumers Electricity producers TSO Government Society/environment	Affected areas	System operation Operational planning Asset management System development

This section introduces the main cost and benefit terms of the SEIA in the context of socio-economic surplus, i.e. the sum of consumer surplus, producer surplus, TSO surplus, government surplus and environmental surplus. The analysis of the surplus of specific stakeholder groups is treated in section 3.2, while the detailed analysis of the different stakeholder groups in the different decision-making timeframes is dealt with in section 3.4.

Socio-economic surplus is the difference of consumer benefit and all costs to generate and supply electricity to end-consumers (see section 2.2 for variable definitions). In reduced form – i.e. when sectoral surpluses have been added up and transfers between different stakeholders have been cancelled out – it is given by the following expression:

$$S = Dv - [c_{INT} + c_{TSO} + C_{TSO} + C_{GEN} + (D - u)(c_{GEN} + c_{ENV})] \tag{3.1}$$

Note that government surplus does not enter into social surplus, since the terms involved (taxes on electricity) are transfers from different stakeholders to the government and cancel out when the sectoral surpluses are added up.

3.1.1 Consumer benefit

Adam Smith famously wrote that “Consumption is the sole end and purpose of all production”[9].[11]. Indeed, the role and social objective of electricity producers, retailers, TSOs, DSOs, etc. is to supply electricity to those consumers requesting it. End-consumers derive benefit – utility or added-value – from electricity consumption: a comfortable temperature from electrical heating and cooling, cooked food from an electrical cooker or microwave, a longer food storage time from a fridge or freezer, visibility at night from lightbulbs, finished products from a manufacturing plant, etc.

Unfortunately, measuring the benefit arising from electricity consumption is a difficult task since it depends on many factors such as the type of consumer c, the time of consumption t and the location of consumption i. To represent this value of consumption, we introduce the value of served load v_{itc}, expressed in $[€/MWh]$. At each time step of the socio-economic assessment the total consumer benefit is the product of electricity demand D_{ic} and the value of served load v_{ic}:

$$\sum_{i=1}^{I} \sum_{c=1}^{C} D_{ic} v_{ic} \tag{3.2}$$

When comparing socio-economic surplus resulting from two TSO decisions and assuming price-inelastic demand[2] consumer benefit from the consumption of electricity cancels out, leaving only the difference

[2] I.e. demand that is unafffected by changes in the electricity price. This is likely to be a good approximation in the GARPUR context where the emphasis is not on computing consumer surplus as such, but, rather, on comparing

The research leading to these results has received funding from the European Union
Seventh Framework Programme under Grant Agreement No 608540.

in cost of interruptions. Note that important cases of price-flexible demand – e.g. interruptible contracts with energy intensive consumers – can be treated as part of the supply side of the framework.

$$\Delta S = \Delta[c_{INT} + c_{TSO} + C_{TSO} + C_{GEN} + (D - u)(c_{GEN} + c_{ENV})] \quad (3.3)$$

3.1.2 Interruption costs

An electricity interruption has a negative economic impact on electricity consumers: it causes a loss of consumer benefit as well as costs such as broken appliances, spoiled food, failed manufacturing, etc. [10]. Interruption costs are calculated as the product of energy not supplied (ENS) [MWh] and Value of Lost Load [VOLL, €/MWh], denoted by u and V, respectively. The VOLL is the marginal interruption cost with respect to energy not supplied [MWh], i.e. the interruption cost of an additional 1 MWh interruption.

$$c_{INT} = uV \quad (3.4)$$

As an example, assume a five-hour interruption of 3 MW and a VOLL of 5000 €/MWh:

$$c_{INT} = uV = 15\, MWh * 5{,}000\, €/MWh = 75{,}000\, €$$

The VOLL is not a constant value. In general, it will depend on several characteristics, such as:

- consumer type
- location of the consumer
- time of interruption
- duration of interruption
- advance notification of interruption
- weather at the time of interruption
- urban area vs rural area
- previous quality of supply

Depending on the availability of detailed VOLL data, the above characteristics could be taken into account in the calculation of interruption costs. Reference [2] explains in detail how to calculate interruption costs using the data of the Norwegian Cost of Energy Not Supplied (CENS) regulation [11]. This data differentiates VOLL according to consumer type c, time of interruption m (time of day, type of day, season), duration of interruption d, and advance notification of interruption n, i.e. $V(\mathrm{c}, \mathrm{m}, \mathrm{d}, \mathrm{n})$.

The interruption cost for a specific hour is calculated as the sum – over all regions, consumer types and interruption durations – of the product of ENS and VOLL, where VOLL depends on the moment of interruption and advance notification of the interruption.

$$c_{INT} = \sum_{i=1} \sum_{c=1} \sum_{d=1} u_{icd} V_{icd}(\mathrm{m}, \mathrm{n}) \quad (3.5)$$

To illustrate this, consider the UK data of VOLL, differentiated according to time of interruption and consumer type, as represented in Table 3.2. Suppose that on a winter weekday during peak hours 100

different reliability related decisions. See chapter 5 for a further discussion of this assumption. It may be noted that where TSOs have implemented simulation models, for the analysis of reliability related decisions, that allow for price-elastic demand this is an improvement on the framework proposed here.

The research leading to these results has received funding from the European Union
Seventh Framework Programme under Grant Agreement No 608540.

MW of domestic consumers and 200 MW of SME[3] demand are interrupted for 3 hours. The interruption cost is:

$$c_{INT} = 300\ MWh * 11{,}820 \frac{£}{MWh} + 600\ MWh * 39{,}863\ £/MWh = 27{,}463{,}800\ £$$

If the same interruption would occur on a non-winter weekday outside of peak hours, the interruption cost would be:

$$c_{INT} = 300\ MWh * 6{,}957 \frac{£}{MWh} + 600\ MWh * 36{,}887\ £/MWh = 24{,}219{,}300\ £$$

Table 3.2 VOLL [£/MWh] (willingness-to-accept) of UK domestic consumers and small and medium-sized enterprises (SMEs) [12]

	Not winter				Winter			
	Off peak		Peak		Off peak		Peak	
	Weekend	Weekday	Weekend	Weekday	Weekend	Weekday	Weekend	Weekday
domestic	9,550	6,957	9,257	11,145	10,982	9,100	10,289	11,820
SMEs	37,944	36,887	33,358	34,195	44,149	39,213	35,488	39,863

3.1.3 TSO costs

The TSO incurs different costs while managing the reliability of the transmission system. Some of these costs are incurred in real-time operation, while others are incurred well before real time. Table 3.3 lists a non-exhaustive sample of types of TSO costs in the different decision making contexts.

Table 3.3 Examples of TSO costs in the different decision making contexts.

Real-time operation	Operational planning	Asset management	System expansion
Losses	Preventive actions	Replacement inspection	Materials and assembly
Corrective actions	Scheduling	Repair	Dismantling
Preventive actions	Reserve procurement	Maintaining stock	Consenting
Congestion management	Congestion management	Planned outage	Research and planning

The actual cost functions are TSO specific, and depend on the system characteristics, the operations and maintenance (O&M) policy, regulation, the reliability criterion, etc. These are further described in[13], [14] and [15].

The SEIA splits TSO costs into short-term costs c_{TSO} that change each time step (e.g. of 1 hour) like losses, preventive actions, congestion management; and costs C_{TSO} like reserve procurement, maintenance and investment costs, that are fixed in the short term, but vary in the medium and long term. These have gains that extend beyond the specific time step in which the expense is incurred. These types of expenditures are to be compared with the short term costs that can be saved via these expenditures.

[3] "SME" is an acronym for "Small and medium-sized enterprises".

The research leading to these results has received funding from the European Union
Seventh Framework Programme under Grant Agreement No 608540.

3.1.4 Producer costs: variable and fixed

Generating electricity entails costs: building power plants, burning fuel, payroll expenses, maintenance, consenting, etc. In the current, restructured electricity market, private generating companies invest in generation capacity with the aim of earning a rate of return on their investment by selling electricity to consumers with a profit.

Economics divides producer costs into variable costs c_{GEN} [€/MWh] such as fuel costs, that vary with output, and fixed costs C_{GEN} like investment costs, that are independent of output. Producer costs are highly heterogeneous – they differ in generation technology, age of the generation plant and its equipment, location, etc. – and exact estimation of variable and fixed cost of specific power plants is difficult. However, this is not critical for the SEIA methodology, since only those costs that change with different reliability decisions need to be considered.

Additional producer costs from reliability-related TSO decisions are damage to equipment[4], increased generation costs (start-up costs or lower efficiency) and lost profits resulting from a missed opportunity to sell electricity. This could be a non-negligible cost but should be considered on a case-by-case basis.

When calculating producer costs, congestion costs are also accounted for. In the present context, congestion costs are the additional generation costs due to the presence of transmission constraints in the transmission grid. That is, congestion costs are the difference in generation costs between a system of infinite transmission capacity and an actual system. In order to alleviate congestion, cheap generation in an export-constrained node needs to be reduced, while more expensive generation in an import-constrained node needs to be increased.[5]

Congestion costs may be reflected in transfers between stakeholders depending on market regimes and regulation. Such transfers do not affect the social congestion costs, but will typically have an impact on the surplus of individual stakeholders. In particular, congestion may have a positive or negative impact on TSO profits depending on whether congestion occurs between price areas or within a uniform price area. When congestion occurs between price areas – either within a single TSO zone or between two TSO zones – they are borne by producers and consumers; TSOs are then unaffected and may actually profit from congestion rents on interconnectors under their control. When congestion occurs within a single uniform price area TSOs will typically bear the cost. The reason is that congestion management is the responsibility of the TSO and is done using redispatch or counter trading in uniform-price zones. In that case, the TSO pays a congestion payment to producers that are rescheduled for congestion management purposes. Thus, TSO congestion management costs are taken into account in the calculation of stakeholder surpluses. The net effect of this transfer payment on socio-economic surplus is, however, zero, but rescheduling generation capacity entails an increase of producer costs, which is reimbursed by

[4] Outages could lead to generation unit tripping and, depending on the generation technology, this could lead to physical damages which require increased maintenance and repair costs.

[5] Congestion costs in principle also include consumer surplus lost due to the impact of price changes, due to transmission constraints, on electricity demand. In this report the impact of reliability-related decisions by TSOs are assumed to have a negligible impact on those costs for the activites of operational planning and system operation (short term) and asset management (mid term) and they can therefore be disregarded in the SEIA for those cases. In the longer term, when consumer demand is more elastic, there is an additional deadweight loss due to the impact of price changes on consumer surplus. Direct costs of demand-side management by TSOs should be included in the SEIA. When penetration of smart-grid technologies reaches the level where consumer response at shorter time horizons becomes significant this needs to be taken into account at those horizons as well.

The research leading to these results has received funding from the European Union
Seventh Framework Programme under Grant Agreement No 608540.

the TSO. Note that congestion costs are taken into account in the calculation of generation costs; counting TSO congestion management costs as social costs would lead to double counting.[6]

3.1.5 Environmental costs

In order to assess the full socio-economic impact of different TSO decisions, one also has to include external costs. In the GARPUR setting these are costs that are not directly borne by electricity producers or consumers. The most important external costs in the electricity market are environmental costs caused by emissions, e.g. by SO_x, NO_x and CO_2 from electricity generation.

The costs from emission e_p of a pollutant p is the product of total emissions and emission damage d_p:

$$c_p = e_p d_{p,} \tag{3.6}$$

with $p = SO_x, NO_x, CO_2$, etc. In general, emissions are expressed as [ton/MWh] and damage as [€/ton].

It is important to note that, in order to avoid double counting, for costs that are already internalised in the generation costs only the remaining societal damage should be included here.

$$c_p = e_p\left(d_p - t_p\right). \tag{3.7}$$

Ideally, the price or tax on emissions t_p [€/ton] equals the societal cost d_p of emissions in order to give correct incentives. In that case there are no additional environmental costs to account for.

For example, in Europe the damage of CO_2 emissions is already internalized – albeit only partly and imperfectly – in electricity generation costs through the EU Emissions Trading Scheme. Likewise, NO_x emissions are taxed in France and Sweden, and SO_x emissions are taxed in the USA.

Additional environmental costs from the electricity market are biodiversity costs, noise and visual pollution costs. In principle, these can also be monetized and included in the assessment of environmental costs.

The environmental costs [€/MWh] are given by the following expression:

$$c_{ENV} = \sum_{p} e_p(d_p - t_p). \tag{3.8}$$

3.2 Accounting framework

In the accounting framework, financial flows of the SEIA are accounted for. This can be done from a system and from a stakeholder perspective. Both perspectives require a definition of (sub-)system boundaries delimiting the scope of interest, such as social surplus or consumer surplus. Only those financial flows crossing the respective (sub-)system boundary are taken into account as relevant costs and benefits for the SEIA (cf. Figure 3.1).

[6] See chapter 3 of [2] for a further discussion of the distinction between social costs and transfers between stakeholders.

The research leading to these results has received funding from the European Union
Seventh Framework Programme under Grant Agreement No 608540.

From the system perspective, the social surplus is obtained as the difference between consumer utility – the ultimate purpose of economic activity – and system costs, i.e. payments made by parts of the system (actors like consumers, producers or TSOs) to other parts of the economy outside the system boundary. Consumer utility arises in our case from electricity consumption and it may be monetized by willingness to pay, which is quantified in electricity system analysis by value of served load or value of lost load (cf. section 3.1). System costs include generation and grid costs both of which comprise capital and operational costs. System costs and consumer utility as determinants of social welfare are placed outside the system boundary, thereby representing the economic input and output to the system (cf. Figure 3.1).

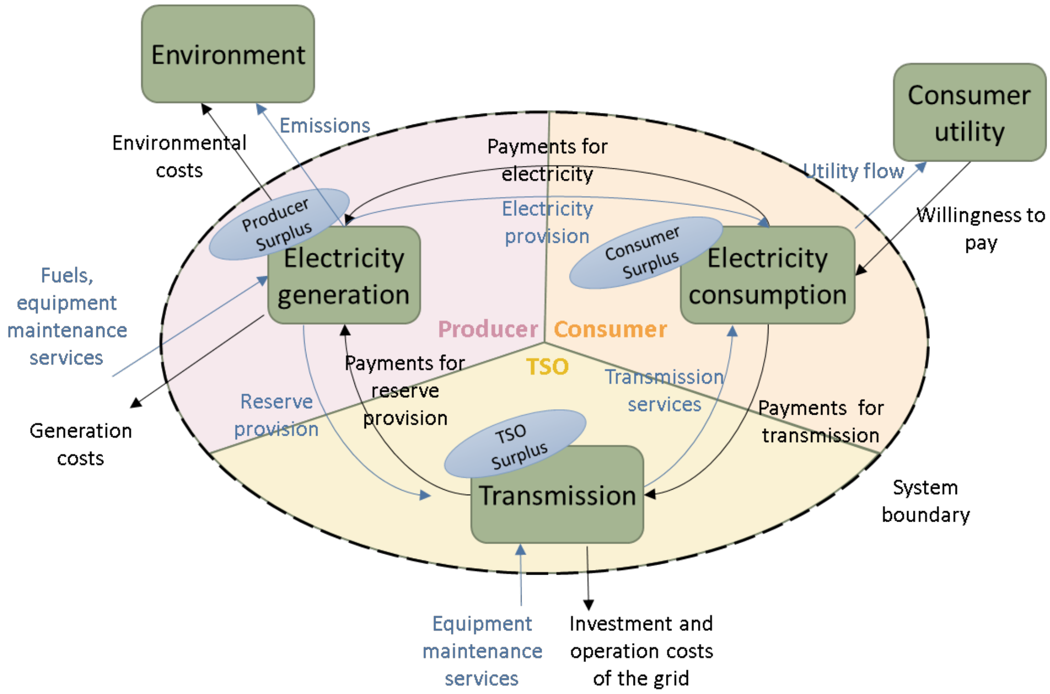


Figure 3.1 System costs and benefits, and transfer payments between stakeholder groups.

Within the system boundary, the main system activities, i.e. generation, transmission and consumption of electric power occur. In the graphical representation of Figure 3.1 these activities are connected by arrows representing the flows of goods and services between the actors and the corresponding financial flows in opposite directions. The fundamental relationship between generation and consumption is the provision of electric power, which is recompensed by payments for electricity. Transmission necessary to connect generation and consumption is remunerated by payments for transmission services. A further relation is the provision of system services by the generators paid for by the TSO.

For the SEIA at a stakeholder level, surpluses are calculated by accounting for financial flows received from and paid to other actors beyond the sub-system boundary. Thereby, financial flows may arise within or beyond the system boundaries. These financial flows are inputs to the relevant balances as presented in Table 3.4 in a stylised way.

Table 3.4 furthermore shows that the internal financial flows within the system boundaries – also referred to as *transfers* – are irrelevant for the SEIA from the system perspective. Each internal financial flow implies both, a cost to one of the stakeholders and a benefit to another stakeholder at the same time; taxes on electricity are one example of a transfer. Consequently, these cancel out by netting costs and benefits when adding up all stakeholders' balances.

The research leading to these results has received funding from the European Union
Seventh Framework Programme under Grant Agreement No 608540.

The stylised balances discussed in this section and depicted in Table 3.4 present a condensed form of the SEIA assessment framework and are further elaborated in the subsequent sections. Notably, they build the basis for the implementation of the SEIA framework discussed in chapter 4. More specifically, the items of the system and stakeholder balances are taken up in the formulas to calculate the respective surpluses in section 4.1.

Table 3.4 System and stakeholder balances

System balance	Stakeholders' (Sub-system) balances		
	Consumer balance	**Producer balance**	**Transmission balance**
+ Consumer utility - Generation costs - Investment and operation costs of the grid	+ Consumer utility - Payments for Electricity - Payments for Transmission + Payments for Flexibility services	+ Payments for Electricity + Payment for reserve provision - Generation costs	+ Payments for Transmission - Payments for Flexibility services - Payment for reserve provision - Investment and operation costs of the grid
= Social surplus	= Consumer surplus	= Producer surplus	= TSO surplus

The definition of the system boundaries as well as the differentiation between various stakeholders refer to the first two attributes discussed in section 3.1, i.e. *assessed markets* and included *stakeholder groups*. In addition to these, also the temporal scope is of major importance for the accounting framework. Similar to the spatial definition of system boundaries, a temporal delimitation of system boundaries allows for derivation of the relevant time period and identification of financial flows that cross the temporal system borders. The impacts of intertemporal financial flows and the methodology of taking them into account is discussed in section 3.3 in more detail.

Another important aspect of accounting within the SEIA is to avoid double counting. Double counting means to consider an item (regardless whether cost or benefit) twice or multiple times. For example, consider the costs resulting from a service interruption. If the economic loss, consumers suffer during a service interruption, is accounted for in the consumer surplus it is inconsistent to additionally penalise TSOs for this service interruption, unless the penalty comes in the form of a financial transfer to another stakeholder (e.g. consumers or the regulator) which is accounted for, both at the TSO level and at the receiving stakeholder level. Conversely, if TSOs are financially penalised for the service interruption this has to be taken into account when assessing the impact on consumers, i.e. by reducing the loss of consumer surplus, resulting from the interruption, by the amount of the penalty payment.[7]

Another example is the consideration of environmental costs induced by emissions, especially of CO_2. These are partly internalised by the EU Emission Trading System. However, it can be argued that the associated price does not appropriately reflect environmental costs of CO_2 emissions. Hence, a further

[7] If the penalty payment is transferred to the consumers and not to the government for example.

The research leading to these results has received funding from the European Union
Seventh Framework Programme under Grant Agreement No 608540.

item accounts for those environmental costs not yet internalised (cf. section 3.1.5). The graphical illustration (as in Figure 3.1) helps to structure and consistently account for financial flows.

3.3 Multiple time horizons

In the GARPUR Project, three time horizons are differentiated. These are directly connected to TSO main tasks at the core of the project: real-time operation and operational planning, asset management, and system development. Moreover, decisions taken at one point in time may have financial implications also at later points in time, e.g. the operational revenues and cost associated with the investment in a new transmission line. Hence, the SEIA framework has to deal consistently both with material consequences (cf. section 3.3.1) and with financial consequences of decisions (cf. section 3.3.2). Any results obtained also have to be interpreted taking into account the assumptions and choices made beforehand.

3.3.1 Multiple decisions at different time horizons

Decisions at different time horizons may also involve different actors such as TSOs, producers and consumers. However, considering multiple actors in the analysis requires to additionally consider the interplay of their decisions. Similar to TSOs, producers are faced with issues within each of the time horizons, such as decisions on investing into power plants, maintaining and operating these assets. The fact that these issues neither occur simultaneously nor have to be dealt with by the same actor implies a sequential multi-level decision process. Consequently, even in this simple form, considering the basic decisions at each time horizon for each of two decision-takers, results in a process with at least seven decision stages:

1. Investment into generation plants
2. Investment into transmission grid
3. Maintenance of generation plants
4. Maintenance of transmission grid
5. Determination of available transmission capacity
6. Operation of power plants
7. Operation of transmission grid.

One could add any number of further decision stages to this exemplary catalogue e.g. by considering consumers' decisions such as demand response.

The more detailed the consideration of multiple decision stages the more complex the related analysis will be. Hence, there is a trade-off between the detail of reality depiction and concessions to the feasibility of the methodology. This does not only hold for the modelling of the interrelated decisions but also applies to a socio-economic evaluation such as the SEIA.

Notably, for any approach, including the SEIA, several issues arise when focusing on implications of a decision (or the comparison of alternative decisions) within a single decision stage. These regard the assumptions on prior and subsequent decisions at higher and lower levels, and the implications of the decision at stake on costs and benefits arising at other decision levels and in other time periods.

The first inter-decision level issue is the assumption on decisions made at lower levels when making decisions at a higher level. These assumptions describe how decision makers anticipate future decisions at an earlier decision point. A fully rational decision maker would anticipate all possible future states of the world and the corresponding optimal decisions at lower levels. The more detailed the decision process and the more realistic the setting, the more difficult is the description of full anticipation. Yet,

The research leading to these results has received funding from the European Union
Seventh Framework Programme under Grant Agreement No 608540.

results obtained using simplified approaches have to be interpreted taking into consideration the simplifying assumptions used for the lower decision level. An example for such a setting is the decision on how much transmission capacity to install while anticipating later operation of generation and transmission capacity.

Assumptions on decisions taken before the moment of the decision at stake are of similar importance (in case input of the SEIA does not result from real observations). These regard e.g. assumptions on the existence and state of generation and transmission facilities, i.e. assets resulting from decisions made before the relevant period under consideration. These may influence costs of decisions at other levels. For example, the procurement of reserve power depends on the existing power plant stock. Procurement costs are sensitive to the existence of excess capacity.

3.3.2 Financial impact of decisions at different time horizons

In addition to the substantial physical impact, taking a decision has also financial impacts at different time horizons. An example is the operational decision to temporarily overload transmission lines or transformers. This may negatively affect failure rates and therefore implies that increasing maintenance expenditures have to be considered even though no explicit decisions on the mid-term timeframe are made and the maintenance expenditure will in general only occur after the considered time-period of operational planning.

The concept of “present value” is used in business administration to map revenues and expenditures (cash flows) occurring at different moments in time, through discounting, to one single accounting period. Depreciation is the most important example of costs which do not correspond to expenditures in the same period. For the assessment of decisions within one time-period, the depreciation resulting from earlier decisions is not relevant, since these are “sunk costs”, which cannot be altered or recaptured. On the other hand, financial consequences of current decisions, which occur during later periods, must be taken into account in a sound SEIA. Important examples are maintenance expenditures resulting from operational decisions or the future expenditures and revenues related to an investment decision.

The consideration of costs and benefits of timeframes beyond the one of the decision to be taken requires an appropriate design of the accounting framework. For investment and other long-term decisions, two different methodologies are commonly applied for intertemporal assessment:

1) Calculating net present values (NPV), and
2) Calculating annualised costs and benefits

The first method relates all financial flows to the moment in which the decision is taken. This is done by discounting future cash flows with a discount rate. This method is common practice in investment projects and also applied in the ENTSO-E Guideline for Cost Benefit Analysis of Grid Development projects [8]. The second method relates financial flows to a representative year. The necessary annualisation of expenditures and revenues does also require an interest rate and assumptions on asset lifetimes. While equations for the calculation of the NPV display this information explicitly, annualised values include it implicitly. For the formal representation of the SEIA in the next chapter, the NPV methodology is chosen.

3.4 Multiple consumer groups

Consumers differ in multiple aspects. Some consumers live in remote regions with a high cost of providing a certain reliability level, while others live in densely populated areas where this cost is lower. Some consumers have a high VOLL, while others have a lower VOLL. This section studies the distributional

The research leading to these results has received funding from the European Union
Seventh Framework Programme under Grant Agreement No 608540.

aspects of multiple reliability criteria on the costs of different consumer groups. In addition, we discuss the effect of transmission tariffs on these costs.

To demarcate this discussion we only focus on TSO costs, c_{TSO}, and interruption costs, c_{INT}. We neglect producer costs and environmental costs.

For illustrative purposes it is assumed here that the TSO cost [€/MWh] to reach a certain reliability level ρ is given by the following specific function:

$$c_{TSO} = \frac{\mathrm{A}\rho}{1-\rho}$$

Here ρ is defined as $\frac{total\ demand - expected\ energy\ not\ supplied}{total\ demand}$, i.e. how much of electricity is supplied when demanded, and A is a cost parameter. This specific family of cost functions only allows for qualitative conclusions. However, it indicates the relationship between reliability level and costs to reach that level: costs tend to zero as reliability approaches zero and are increasing, convex and approach infinity as reliability tends to 100%. In particular, costs increase without bounds as the system approaches a level without any interruptions.

If VOLL is represented by V, interruption costs [€/MWh] are given by:

$$c_{INT} = (1-\rho)V \tag{3.9}$$

In absence of producer and environmental costs, a TSO chooses a (perfectly regulated) reliability level ρ for its zone that minimizes the sum of TSO costs c_{TSO} and interruption costs c_{INT}:

$$\min_{\rho} \left\{(1-\rho)V + \frac{\mathrm{A}\rho}{1-\rho}\right\} \tag{3.10}$$

This leads to the following optimal reliability level:

$$\rho^* = 1 - \left(\frac{\mathrm{A}}{V}\right)^{0.5}, \tag{3.11}$$

which is decreasing in the TSO cost parameter and increasing in the VOLL. That is, the optimal reliability level increases with the cost of interruptions (VOLL), but decreases with the cost of attaining a certain reliability level.

To illustrate the distributional aspects of multiple reliability criteria on the costs of different consumer groups, we apply the above model of TSO costs and interruption costs to a simple two-region country setting. First, we treat the case where the TSO costs c_{TSO} of attaining a certain reliability level differ between the two regions. Next, we consider the case where VOLL differs between the two regions. The TSO is able to provide different reliability levels in the two regions. The two regions are equal in size.

3.4.1 Different reliability costs

The two regions are labelled *H* – indicating high cost – and *L* – indicating low cost. Indeed, suppose that the TSO cost, c_{TSO}, of attaining a certain reliability level is higher in one region than the other: $A_H > A_L$. For example $A_H = 0.02$ and $A_L = 0.005$.

The research leading to these results has received funding from the European Union
Seventh Framework Programme under Grant Agreement No 608540.

We compare five different reliability criteria: The N-1 reliability criterion, which is the starting point and benchmark of the analysis, and four alternative probabilistic reliability criteria that could replace the currently used N-1 reliability criterion.

(1) The **N-1 reliability criterion**. This is the benchmark criterion with corresponding reliability levels, ρ_H and ρ_L, in region *H* and *L,* respectively. As an arbitrary starting point, assume $\rho_H = 0.9985$ and $\rho_L = 0.9987$.
(2) A **probabilistic reliability criterion** that minimizes the sum of total costs, i.e. equation (3.10).
(3) A **probabilistic reliability criterion with a Pareto-improvement in total costs**, i.e. each consumers' total cost ($TC = c_{INT} + TT$) does not increase when moving from N-1 to a probabilistic reliability criterion.
(4) A **probabilistic reliability criterion with a Pareto-improvement in reliability levels**, i.e. each consumer's reliability level does not decrease when moving from N-1 to a probabilistic reliability criterion.
(5) A **probabilistic reliability criterion with a minimum reliability level** ρ_{min}. The minimum is to be enforced across all consumers. This minimum reliability level is determined exogenously, for example by a regulator.

Here it is assumed that TSO costs $\frac{c_{TSO,H}+c_{TSO,L}}{2}$ [€/MWh] are remunerated by levying a uniform transmission tariff TT [€/MWh] on all consumers; in other words, *TT* will change with total TSO costs, but all consumers pay the same tariff rate – except in the Pareto case (3) where tariffs decrease for consumers experiencing a lower reliability level. Table 3.5 shows numerical results for the illustration.

Table 3.5 Illustrative comparison of costs for two regions i for five reliability criteria

$c_{TSO,i}$= reliability cost in region i, TT=transmission tariff=average TSO cost, $c_{INT,i}$=interruption cost, TC_i=total cost for a consumer in zone i, AC=average total cost [€/MWh]. $A_H = 0.02$, $A_L = 0.005$ and $VOLL_H = VOLL_L = 5{,}000$ €$/MWh$.

		ρ_H	ρ_L	$c_{TSO,H}$	$c_{TSO,L}$	TT	$c_{INT,H}$	$c_{INT,L}$	TC_H	TC_L	AC
(1)	N-1	0.9985	0.9987	13.3	3.9	8.6	7.5	6.5	**16.1**	**15.1**	<u>15.6</u>
(2)	Prob.	0.998	0.999	10	5	7.5	10	5	**17.5**	**12.5**	<u>15</u>
(3)	Pareto C	0.998	0.999	10	3.9	6.1/8.9	10	5	**16.1**	**13.9**	<u>15</u>
(4)	Pareto ρ	0.9985	0.999	13.3	5	9.2	7.5	5	**16.7**	**14.2**	<u>15.4</u>
(5)	ρ_{min}	0.9986	0.999	14.3	5	9.6	7	5	**16.6**	**14.6**	<u>15.6</u>

*The reliability level in: (1) is an assumption; (2)&(3) is calculated from equation (3.11); (4) is constrained by the reliability level in case (1); (5) is assumed to be minimally 0.9986 in both regions.

For a more detailed analysis of the different costs of the five reliability criteria of Table 3.5 , we refer to[2]. We limit ourselves to discuss the main results and its implications for policy making.

1. Different reliability criteria lead to different total costs TC (bold numbers) for different consumer groups. Some consumers experience an increase of total costs, while others experience a decrease. In general, high-cost consumers (i.e. those in high-cost areas) experience a cost increase while low-cost consumers experience a cost decrease, because it is optimal to increase the reliability level of consumers with a low TSO cost and decrease it for high-cost consumers. As a result, high-cost consumers could dislike the change to probabilistic reliability criteria.

2. Average total costs AC (underlined numbers) decrease when moving from the N-1 reliability criterion (1) to a probabilistic reliability criterion without constraints (2), because the TSO better

The research leading to these results has received funding from the European Union
Seventh Framework Programme under Grant Agreement No 608540.

aligns costs and benefits. However, the probabilistic reliability criterion amounts to decreasing the reliability level of high-cost consumers. As a result, they will experience an increase in total costs. Adding constraints like Pareto total costs (3), Pareto reliability level (4) or minimum reliability level (5) reduces this cost increase but increases average total cost once again. This is a fundamental economic discussion of *economic efficiency versus equity*. Imposing limits on inequality (like a minimum or universal reliability level, not raising costs of high-cost consumers, etc.) decreases efficiency but is generally considered to be more fair.[8] Striking the balance between these opposing objectives is the role of a regulator, based on society's preferences.

3. All five reliability criteria entail a transfer from low-cost consumers to high-cost consumers, because the uniform transmission tariff socializes TSO costs over all consumers. This is a discussion of *individualism versus solidarity.* That is, does every consumer pay for the cost he imposes on the system or are costs socialized? This is an issue regardless of the change of reliability criterion and should be decided by the regulator, again based on society's preferences. In addition, socialization of TSO costs entails an economic inefficiency since consumers are not exposed to their own social cost and thus do not make socially efficient choices. This aspect is, however, not captured by the above illustrative example.

3.4.2 Different VOLL

In this section the above analysis is redone for two regions with equal TSO costs but different VOLL: $VOLL_H > VOLL_L$. For example $V_H = 5{,}000$ [€/MWh] and $V_L = 1250$ [€/MWh]. In this case we compare outcomes for consumers that value interruptions differently instead of consumers that choose to live in regions with different TSO costs. Table 3.6 shows numerical results for the illustration. Note that the reliability criteria are the same as in section 3.4.1. Interruption costs and total costs are, however, lower due to much lower VOLL in region *L.*

Table 3.6 Illustrative comparison of costs for two regions i for five reliability criteria

$C_{TSO,i}$= reliability cost in region i, TT=transmission tariff=average TSO cost, $C_{INT,i}$=interruption cost, TC_i=total cost for a consumer in zone i, AC=average total cost [€/MWh]. $A_H = A_L = 0.005$, $VOLL_L = 1{,}250$ €$/MWh$ and $VOLL_H = 5{,}000$ €$/MWh$.

		ρ_H	ρ_L	$c_{TSO,H}$	$c_{TSO,L}$	TT	$c_{INT,H}$	$c_{INT,L}$	TC_H	TC_L	AC
(1)	N-1	0.9985	0.9987	3.3	3.9	3.6	7.5	1.6	**11.1**	**5.2**	8.2
(2)	Prob.	0.999	0.998	5	2.5	3.75	5	2.5	**8.75**	**6.25**	7.5
(3)	Pareto C	0.9985	0.999	5	2.5	4.8/2.7	5	2.5	**9.8**	**5.2**	7.5
(4)	Pareto ρ	0.999	0.9987	5	3.9	4.4	5	1.6	**9.4**	**6**	7.7
(5)	ρ_{min}	0.999	0.999	5	5	5	5	1.25	**10**	**6.25**	8.1

The analysis with different VOLLs leads to additional results and implications for policy making.

4. Moving to a probabilistic reliability criterion (2) implies that, optimally, high-VOLL consumers receive a higher reliability level and low-VOLL consumers receive a lower reliability level. These high-VOLL consumer thus experience a total cost decrease, while low-VOLL consumers

[8] In economic theory, it has been shown that addressing income inequality can be done more efficiently via progressive income taxes than by distorting some attributes of a consumer product like prices, quantities or quality[16].

The research leading to these results has received funding from the European Union Seventh Framework Programme under Grant Agreement No 608540.

experience a total cost increase. This could be considered unfair by low-VOLL consumers. This is a fundamental economic discussion of *“economic efficiency versus fairness”.* Again, imposing limits on the probabilistic criterion decreases efficiency but is generally considered to be more fair. One solution is to let high-VOLL consumers pay a higher transmission tariff (3). Striking the balance between these opposing objectives is the role of a regulator, based on society’s preferences.

3.5 Multiple countries, regions, TSOs

Most transmission systems consist of different interconnected networks, each of which governed by one TSO. Especially on the continental power system, where grids of neighbouring countries are interconnected, the degree of TSOs cooperation, or lack of it, can have an impact on costs of attaining desired reliability levels and the degree of reliability in different regions.[9] In general, overall costs are likely to fall with TSO cooperation, allowing for lower transmission tariffs and/or provision of increased overall reliability. This does not, however, imply that everyone will necessarily be better off: distributional consequences are likely to ensue. As an illustration of the issues that are likely to arise in such situations this section considers a particular sphere of TSO cooperation, *viz.* the determination of levels of needed reserves in each TSO zone and the extent to which they are shared, procurement costs and the incentives that TSOs face.

The cooperation of adjacent regions on reserves procurement can bring substantial benefits. Such cooperation between adjacent areas will gain importance with increasing amounts of intermittent renewable generation entering the power grid, especially when the regions/countries in question have uncorrelated reserves costs and needs.

Here two forms of TSOs cooperation in reserves provision are considered: a scenario in which TSOs acquire reserve capacity in the adjacent TSO area – exchange of reserves and cost arbitrage; and reserves sharing – a scenario allowing for pooling of reserve needs as well as cost arbitrage. A non-cooperative scenario where TSOs do not share any element of the reserves provision process – each TSO is in *autarky* – comes at an increased cost to TSOs as they cannot use any benefits of cost reduction across regions. Exchange of reserves allows that part of the required level of reserves to be procured from adjacent regions. These reserves are exclusively for one TSO, meaning that they cannot contribute to meeting another TSO’s required level of reserves. The reserve capacity remains in the reserve-providing TSO zone, however, if needs arise the exchange results in physical delivery of power to the reserves-receiving TSO. Reserves sharing allows for a much deeper integration and is especially beneficial, over and above the benefits provided by reserves exchange, when costs in both regions are fairly similar and the correlation of reserve needs is low. This scenario allows multiple TSOs to take into account the same reserves to meet their reserve requirements resulting from reserve dimensioning. Provided that cooperating TSO regions have not perfectly correlated reserve needs, sharing of reserves yields the highest reduction of costs/benefits.

Current regulation stipulates that TSOs use the autarkic reserve levels – i.e. those determined for each TSO zone separately, prior to any cooperation on reserves – as given and subsequently rely on exchange of reserves to minimize costs. Hence, the level of reliability is the same with reserves exchange as in the non-cooperative (autarkic) case. Clearly, the overall expected socio-economic surplus with reserves exchange is no smaller than that in autarky, since costs of reserves procurement are lower and reserve levels and interruption costs are the same. However, in case the zones are perfectly symmetric, exchange

[9] Other examples of issues with multiple TSO regions include the setting of the net transfer capacities between countries and new investments in cross-border capacities.

The research leading to these results has received funding from the European Union
Seventh Framework Programme under Grant Agreement No 608540.

as such offers no advantage – pooling of reserve needs – reserve sharing – is then necessary to improve on autarky. Thus, each step in the integration of zones results in progressively higher expected socio-economic surplus.

Another important issue to note is that when the zones have different costs of reserves procurement, there will be distributional consequences of reserves exchange. Reserve costs will fall in the high-cost zone and rise in the low-cost zone. Hence, a side compensation that will make exchange incentive compatible for TSOs is necessary. The result of bargaining for such compensation can be predicted by the Nash bargaining solution. Under uniform pricing it would split the surplus resulting from cooperation on reserves between regions participating in the exchange in such a way, that, as a result, each region will be left with the half of the difference between one region's surplus less the other region's loss [17].

With reserves sharing, there may also be distributional consequences that TSOs and/or consumers in one zone are better off and those in the other worse off, both as regards reserves costs and expected interruptions. Similar to reserves exchange, in order for reserves sharing to be incentive-compatible for these stakeholders a minimal side payment is necessary from the zone where the TSO and/or consumers gain from sharing to the one where they are made worse off.

Comparison of the three degrees of TSO cooperation in generation of reserve provision: autarky, reserves exchange and reserves sharing, indicates the efficiency of cooperation. The benefits of reserves exchange and reserves sharing depend on cost asymmetry and correlation of reserve needs between the TSO zones. That is, when TSO zones have highly asymmetric reserve procurement costs but highly correlated reserve needs, reserves exchange already yields a high cost reduction. When TSO zones have fairly equal reserve procurement cost but a low degree of reserve needs correlation, reserves sharing is needed to reap the full benefits of TSO reserves cooperation.

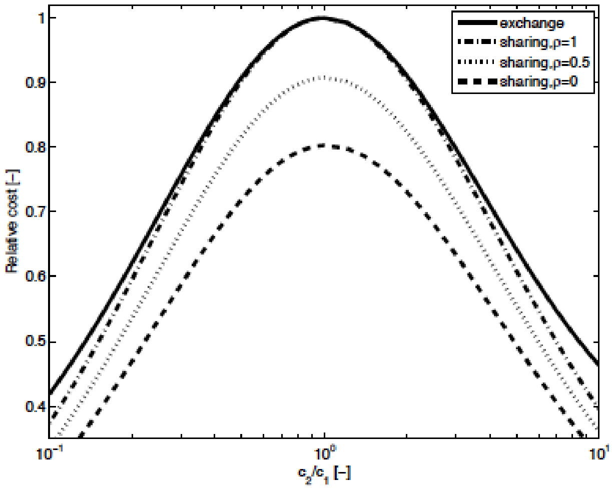


Figure 3.2 Relative cost of reserves exchange and reserves sharing, as a function of the cost asymmetry ($\boldsymbol{c_1}/\boldsymbol{c_2}$) and the reserve needs correlation ($\boldsymbol{\rho}$).

Figure 3.2 [18] shows the sum of interruption costs and procurement cost under reserves exchange and reserves sharing, relative to the autarkic costs. It indicates, that the benefits of exchange increase with cost asymmetry (C_1/c_2) and that the benefits of sharing increase with the decrease of reserve needs correlation (ρ).

The research leading to these results has received funding from the European Union
Seventh Framework Programme under Grant Agreement No 608540.

To sum up:

- In cases when adjacent TSO regions have differing procurement costs and reserve needs, cooperation is beneficial as it decreases costs.
- Distributional effects are present when TSOs start to cooperate on short-term reliability management.
- The optimal type of reserve procurement method depends on: the correlation of procurement costs, reserves needs and the value of lost load.
- When two TSO zones have identical procurement costs, no cost arbitrage is possible and exchange of reserves does not yield any cost reduction – reserves sharing is necessary to improve on the non-cooperative outcome.
- When the cost of reserve procurement differs between TSO zones, reserves exchange yields a cost reduction.
- The costs reduction decreases when the reserve needs in the two TSO zones are more correlated.
- When the reserve needs are fully correlated, reserves sharing yields almost no additional cost reduction compared with reserves exchange.
- With symmetric costs and highly correlated reserve needs, cross-border cooperation in reserves yields very little cost reduction.
- Each step in the integration of zones results in progressively higher expected socio-economic surplus.
- In case of asymmetric zones, additional payments will be necessary to make cooperation incentive-compatible.

The research leading to these results has received funding from the European Union
Seventh Framework Programme under Grant Agreement No 608540.

4 IMPLEMENTATION OF THE SOCIO-ECONOMIC IMPACT ASSESSMENT FRAMEWORK

This chapter describes the implementation of SEIA in detail for each activity category, or time frame, specified in the GARPUR approach, namely operational planning and system operation (short term), asset management (mid term) and system development (long term). The implementation takes into account that there may be several regions under consideration in the SEIA, whose social surplus as a whole is the main economic measure of impact in the SEIA. In section 4.1, full mathematical formulas are provided for social surplus as a whole and social and sectoral surplus in each region. It is, however, important to note that the formulas may need to be adapted to the particular case under consideration; in particular, differences in regulation of the electricity market, taxation and environmental fees (prices of emission permits or taxes imposed on emissions) need to be taken into account in final implementation. Section 4.2 details data requirements for an SEIA. Finally, section 4.3 considers input (data and parameter) collection issues for TSOs as they prepare the execution of an SEIA.

4.1 Full formulas for different time frames – breakdown by sectors

In this section, the SEIA is derived for the different time horizons and main tasks of the TSO by presenting specific formulas for each actor and emphasising characteristics. This shall contribute to a detailed understanding and serves as input for section 4.2 where data requirements are highlighted.

4.1.1 Operational planning and system operation

In the short-term, TSO decision making is either linked with preventive or corrective control measures in response to events threatening the system security or adequacy. A detailed list and description of the TSO actions for the short-term horizon can be found in [15]. In the following, formulas for the SEIA are reshaped for the short-term horizon. In contrast to the more general formulation in section 3.1, these are not only specific for the different actors but are also more detailed with respect to issues such as consumer types and generation technologies.

Due to the fact that the methodology shall be applicable within a multi-region system, we present the formulas aggregating for specific actors at nodes i within a region r, $i \in I_r$. Each region $r \in R$ consists of a certain number of nodes $i \in I_r$, where the nodes are determined by the granularity of the power system model used (e.g. in the GARPUR Quantification Platform). Hence, aggregating over all regions gives the overall actor-specific surplus including all nodes of the considered problem. This is exemplarily shown for socio-economic surplus where formulas, both for the region-specific surplus and the aggregated surplus are given.

Socio-economic surplus

Formula (4.1) provides an expression for the regional socio-economic surplus. It is determined as a present value of flows in each time period of (net) consumer utility from electricity consumption (where the disutility of interruptions has been subtracted) less the sum of TSO costs, generation costs, costs of flows from other regions and environmental costs (a more detailed explanation of the formula is given below): [10]

$$
\begin{aligned}
S_r = \sum_{t=0}^{T} DF_t \Bigg[TS \sum_{i \in I_r} \Bigg(\sum_{c=1}^{C} \Bigg(D_{cit} v_{cit} - \sum_{d=1}^{D} u_{cdit} V_{cdit}\, f_{cit}^{m}\, f_{cit}^{n} \Bigg) - (D_{it} - u_{it}) c_{TSO,it} - \mathrm{C}_{TSO,it} \\
- \sum_{g=1}^{G} \big(c_{GEN,git} y_{git} + C_{gen,git} \big) - \sum_{j \notin I_r} \Big(\frac{1}{2} (p_{it} + p_{jt}) l_{jit} \Big) \\
- \sum_{g=1}^{G} y_{git} \sum_{p=1}^{P} e_{pgit} (d_{pt} - t_{pit}) \Bigg) \Bigg].
\end{aligned}
\tag{4.1}
$$

For the short time horizon used in operational planning and system operation time discounting may be disregarded, i.e. the discount factor may be taken to be $DF_t = 1$. This is linked to the discussion in section 3.3 where the two alternative methodologies to consider intertemporal effects are discussed. For the short-term horizon both alternatives yield the same outcome.

As explained in more detail below, some of the terms in (4.1) may have to be adjusted, depending on the regulation in place in the regions under consideration.

Socio-economic surplus is derived from the utility of electricity consumption, less system costs, both of which are aggregated for given sets of time steps $t \in T$, and of nodes $i \in I_r$ within region r. Single components are furthermore aggregated and explained in the following. Utility of electricity consumed is calculated from consumers' valuation, v_{cit}, of electricity demanded for a given set of consumer types $c \in C$ less disutility V_{cdit} associated with unserved demand for a given set of interruption durations $d \in D$ (cf. section 3.1.2 for a detailed description of interruption costs). Variable TSO costs arise from electricity delivered whereas fixed TSO costs are considered as a lump sum. Similar to the TSO costs, variable generation costs are accounted for generated electricity and fixed generation costs accrue as a lump sum; both are aggregated for a given set of generation technologies $g \in G$. Besides payments occurring within the operational time horizon, these cost terms should include also implied changes in later payments, notably increased or decreased maintenance effort.

Furthermore, in the regional surplus, flows crossing borders to other regions have to be considered. l_{jit} is the amount of electricity transferred from one zone to another, with a positive sign for exports from j to i or for imports by i from j and a negative sign for flows into the opposite direction. The penultimate term in formula (4.1) can be rewritten as

$$
-\sum_{j \notin I_r} \Big(\frac{1}{2} (p_{it} + p_{jt}) l_{jit} \Big) = -\sum_{j \notin I_r} (p_{jt} l_{jit}) - \sum_{j \notin I_r} \Big(\frac{1}{2} (p_{it} - p_{jt}) l_{jit} \Big)
$$

where, depending on the sign of l_{jit}, the first term refers to costs/ benefits from electricity produced or consumed in different regions and the second term takes the congestion rent/ cost into account. E.g. in case of an export from the region where node j is located to the region of node i, the first term considers

[10] Throughout this document, subscripts in capital letters are part of the variable name while those in lower-case letters are indices.

The research leading to these results has received funding from the European Union
Seventh Framework Programme under Grant Agreement No 608540.

the costs of electricity consumed in the region of node i but generated in the region of node j at the local price of the region with node j and the second term assigns half of the congestion cost to the region with node i (and thus half of the congestion rent to the region with node j). This halving is an assumption of rules for distributing congestion rents between concerned TSOs and might differ according to the applicable regulation. Note that cross-border flows are taken as exogenous in the surplus formulas, but will be affected by e.g. the setting of net transfer capacities on interconnectors.

In the last term in formula (4.1), external environmental costs, arising from pollutants $p \in P$ from generating electricity, reduce social surplus.

Formula (4.1) gives an expression for the surplus in a particular region. In general, the SEIA will consider more than one region, which need to be aggregated in a single surplus expression. Formula (4.2) describes the socio-economic surplus aggregated for all regions $r \in R$, i. e. $S = \sum_r S_r$:

$$S = \sum_{t=0}^{T} DF_t \left[TS \sum_{i=1}^{I} \left(\sum_{c=1}^{C} \left(D_{cit} v_{cit} - \sum_{d=1}^{D} u_{cdit} V_{cdit}\, f_{cit}^{m}\, f_{cit}^{n} \right) - (D_{it} - u_{it}) c_{\mathrm{TSO,it}} - C_{TSO,it} \right. \right.$$
$$\left. \left. - \sum_{g=1}^{G} \left(c_{GEN,git} y_{git} + C_{GEN,git} \right) - \sum_{g=1}^{G} y_{git} \sum_{p=1}^{P} e_{pgit} (d_{pt} - t_{pit}) \right) \right] \tag{4.2}$$

In contrast to formula (4.1), it is aggregated over the set of all nodes in the regions under consideration, $i \in I$ – not just the set of nodes in region *r*, I_r – and does no longer include costs and benefits for cross-regional flows since these cancel out in the aggregation over regions.

Consumer surplus

$$S_{CONS,r} = \sum_{t=0}^{T} DF_t \left[TS \sum_{i \in I_r} \left(\sum_{c=1}^{C} \left(D_{cit} v_{cit} - \sum_{d=1}^{D} u_{cdit} V_{cdit}\, f_{cit}^{m}\, f_{cit}^{n} + R^{u,TSO}{}_{cit} \right) \right. \right.$$
$$- D_{it} p_{it} (1 + x_{it}) - (D_{it} - u_{it}) TT_{it} (1 + x_{it})$$
$$\left. \left. - \sum_{g=1}^{G} y_{git} \sum_{p=1}^{P} e_{p,git} (d_{pt} - t_{pit}) \right) \right] \tag{4.3}$$

Consumer surplus is composed of utility from electricity demanded less disutility arising from energy not supplied, a compensatory payment for unserved load paid by the TSO ($R^{u,TSO}{}_{cit}$), payments of taxes, the transmission tariffs and payments for external environmental costs. The existence and exact design of the compensatory payment is subject to regulatory decisions. It is likely to depend on the amount of energy not supplied and may be differentiated among consumer groups analogously to their differentiation of the value of lost load. Irrespective of the energy not supplied, the consumer is assumed to pay for the amount of energy procured on the market. Transmission tariffs, however, are assumed to be charged for the amount of energy served only.

Producer surplus

$$S_{PROD,r} = \sum_{t=0}^{T} DF_t \left[TS \sum_{i \in I_r} \left(\sum_{g=1}^{G} \left(\left(p_{it} - (c_{GEN,git} + t_{\mathrm{pit}}) \right) y_{git} - C_{GEN,git} \right) + f_{it} \right) \right] \tag{4.4}$$

The research leading to these results has received funding from the European Union Seventh Framework Programme under Grant Agreement No 608540.

Producer surplus can be derived from revenues earned for selling electricity less generation costs and the TSO fee for producers. The latter includes the remuneration for ancillary services provided for the TSOs (cf. TSO surplus).

TSO surplus

$$S_{TSO,r} = \sum_{t=0}^{T} DF_t \left[TS \sum_{i \in I_r} \left((D_{it} - u_{it})(TT_{it} - c_{TSO,it}) + \frac{1}{2} \left(\sum_{j \notin I_r} (p_{it} - p_{jt}) \cdot l_{jit} \right) - R^{u,TSO}{}_{cit} - \mathrm{C}_{TSO,it} - f_{it} \right) \right] \quad (4.5)$$

The TSO earns revenues from transmission tariffs, which are subject to national regulation schemes. Additionally, it collects (half) the congestion rent (for congested interconnectors, i.e. if $p_{it} \neq p_{jt}$) and pays a compensatory payment for energy not supplied to the consumers, where rules are also specific to the regulation in place. The TSO furthermore incurs variable and fixed costs e.g. from transmission losses and from applying ancillary services. Relevant services for the short-term horizon include network capacity scheduling and outage scheduling, congestion management, procurement and activation of reserve power. In the context of direct TSO costs, switching as such is regarded as a non-costly measure although costs associated with wear and tear can be considered, i.e. in form of earlier incurring replacement costs. (Indirect) Costs arising from procuring and utilizing these ancillary services are included in the fee paid to producers. An alternative representation of these costs in which specific quantities and prices (e.g. for procuring and activating reserves) are explicitly multiplied, in a similar way as generation costs are taken into account, is also possible.

Government surplus

$$S_{GOV} = \sum_{t=0}^{T} DF_t \left[TS \sum_{i=1}^{I} (D_{it} p_{it} x_{it} + (D_{it} - u_{it})(TT_{it}) x_{it}) \right] \quad (4.6)$$

The government collects taxes on electricity traded and transmitted. If the government levies taxes that are not spent within the system, they add to the aggregate socio-economic surplus at the cost of consumer surplus.

4.1.2 Asset management

A detailed technical description of asset management activities is provided in [14]; for a discussion of economic aspects see [2]. Three main categories of asset management operations can be identified:

1. Asset management operations related to maintaining particular system components – these operations usually involve planned outages.
2. Asset management operations related to failures of system components – these involve unplanned outages.
3. Day-to-day preventive maintenance.

Each of these categories has its particular cost characteristics. There are three main categories of costs and benefits connected to asset management operations:

The research leading to these results has received funding from the European Union
Seventh Framework Programme under Grant Agreement No 608540.

1. Direct cost of the actions involved, e.g. the material and labour cost of replacing a component, as well as provisions for maintenance such as availability of spare parts. These enter as costs in the TSO surplus and social surplus expressions. These costs are in part determined, as part of preventive maintenance, and in part as costs of replacing failed components.
2. Indirect cost resulting from temporary reduction in system capacity when an outage, planned or unplanned, occurs as a result of undertaking maintenance. Such costs include:
    a. Increased costs of energy not supplied. These are a consequence of stochastic outcomes such as failures of system components in operation during the maintenance.
    b. Increased congestion costs (including generation costs) arising as a result of diminished transmission capacity.
3. Indirect benefits, relating to preventive asset maintenance expenditures, resulting from lower failure rates of transmission grid components.

Indirect costs and benefits (items 2 and 3 above) accrue through the probability distribution of variables such as the quantity of energy not supplied. So even if explicit cost terms for indirect costs and benefits they are included in the evaluation when expectations over probability distributions are calculated. For example, if there is a higher expected quantity of energy not supplied for asset management strategy A than strategy B, e.g. due to the timing of a planned outage, then this will be reflected in the calculation of consumer and social surplus. And possibly also in TSO surplus if consumers are compensated for loss of load.

Clearly, for benefits of asset management expenditures, which arise through better system performance (e.g. lower failure rates), to be realised in simulations, the system model needs to include aspects such as links between maintenance expenditures and failure rates. For long-term implications of asset management decisions to be taken into account, the simulation needs to be over a long-term horizon. Alternatively, present values of extrapolated costs and benefits over the relevant time horizon outside the simulation horizon can be added as terminal values.

The formulas below are expressed for a general discount factor. If the time horizon under consideration is less than 1-2 years then the discount factor may be set to one,

$$DF_t = 1.$$

Socio-economic surplus

Formula (4.7) gives the regional socio-economic surplus for the case of asset management. The only difference with equation (4.1) above (the case of operational planning and system operation) is that here, direct asset management expenditures are taken into account. Direct TSO costs of asset management on the line between nodes i and j in time interval t are denoted by a_{ijt}. The set of neighbouring nodes of node i is denoted by J_i.

$$\begin{aligned} S_r = \sum_{t=0}^{T} DF_t \Bigg[TS \sum_{i \in I_r} \Bigg(\sum_{c=1}^{C} \Bigg(D_{cit} v_{cit} - \sum_{d=1}^{D} u_{cdit} V_{cdit}\, f_{cit}^{m}\, f_{cit}^{n} \Bigg) - (D_{it} - u_{it}) c_{TSO,it} - \mathrm{C}_{TSO,it} \\ - \sum_{g=1}^{G} \left(c_{GEN,git} y_{git} + C_{GEN,git} \right) - \sum_{j \notin I_r} \left(\frac{1}{2} (p_{it} + p_{jt}) l_{jit} \right) - \frac{1}{2} \sum_{j \in J_i} a_{ijt} \\ - \sum_{g=1}^{G} y_{git} \sum_{p=1}^{P} e_{p,git} (d_{pt} - t_{pit}) \Bigg) \Bigg]. \end{aligned} \tag{4.7}$$

The research leading to these results has received funding from the European Union Seventh Framework Programme under Grant Agreement No 608540.

Note that the sum over asset management costs is multiplied by $\frac{1}{2}$ to avoid double counting. This also applies to lines connected to nodes outside region r so there is an implicit assumption that asset management costs are split evenly for interconnectors. If this is not the case then the formula needs to be modified accordingly.

When social surplus is aggregated across regions and over all nodes, $i \in I$, cross-regional flows cancel out as in (4.2):

$$S = \sum_{t=0}^{T} DF_t \Bigg[TS \sum_{i=1}^{I} \Bigg(\sum_{c=1}^{C} \Bigg(D_{cit} v_{cit} - \sum_{d=1}^{D} u_{cdit} V_{cdit} \, f_{cit}^{m} \, f_{cit}^{n} \Bigg) - (D_{it} - u_{it}) c_{TSO,it} - \mathrm{C}_{TSO,it} - \sum_{g=1}^{G} \big(c_{GEN,git} y_{git} + C_{GEN,git} \big) - \frac{1}{2} \sum_{j \neq i} a_{ijt} - \sum_{g=1}^{G} y_{git} \sum_{p=1}^{P} e_{p,git} (d_{pt} - t_{pit}) \Bigg) \Bigg] \tag{4.8}$$

Consumer, producer and government surplus

For consumers, producers and the government the surplus expressions are the same as for the case of operational planning and system operation, i.e. (4.3), (4.4) and (4.6), respectively.

TSO surplus

The surplus of the TSO is given by the same formula as for the case of operational planning and system operation (4.5) with the modification that (direct) costs of asset management ($\frac{1}{2}\sum_{j \in J_i} a_{ijt}$) are now taken into account:

$$S_{TSO,r} = \sum_{t=0}^{T} DF_t \Bigg[TS \sum_{i \in I_r} \Bigg((D_{it} - u_{it})(TT_{it} - c_{TSO,it}) + \frac{1}{2} \Bigg(\sum_{j \notin I_r} (p_{it} - p_{jt}) \cdot l_{jit} \Bigg) - R^{u,TSO}{}_{cit} - \mathrm{C}_{TSO,it} - f_{it} - \frac{1}{2} \sum_{j \in J_i} a_{ijt} \Bigg) \Bigg]. \tag{4.9}$$

4.1.3 System development

System development deals with taking decisions that change transmission capacities either within a TSO's own system or towards other TSOs systems, such as [13]:

Construction, upgrading, replacement, retrofitting or decommissioning of assets, like:

- AC or DC high-voltage lines
- substations
- phase-shifting transformers
- shunt reactors
- capacitor banks
- synchronous condensers
- flexible AC transmission systems (FACTS)
- static VAR compensators (SVC)
- series compensation devices
- communication or measurement systems
- etc.

The research leading to these results has received funding from the European Union Seventh Framework Programme under Grant Agreement No 608540.

Additionally, decisions have to be made on the specific type of technology for each of these assets, e.g. a conventional vs. superconductive cable. Likewise, decisions on the timing, location and size of the assets are needed. Furthermore, in the long term, a TSO makes strategic decisions like replacement, maintenance and operational policies, including decisions on reliability management.

Socio-economic surplus

Formula (4.10) gives the regional socio-economic surplus.

$$S_r = \sum_{t=0}^{T} DF_t \Bigg[TS \sum_{i \in I_r} \Bigg(\sum_{c=1}^{C} \Bigg(D_{cit} v_{cit} - \sum_{d=1}^{D} u_{cdit} V_{cdit} \, f_{cit}^{m} \, f_{cit}^{n} \Bigg) - (D_{it} - u_{it}) \mathrm{c_{TSO,it}} - \mathrm{C}_{TSO,it} \\ - \frac{1}{2} \sum_{i=1}^{I_r} \sum_{j \in J_i} a_{ijt} - \sum_{g=1}^{G} \big(c_{GEN,git} y_{git} + C_{GEN,git} \big) - \sum_{j \notin I_r} \Big(\frac{1}{2} (p_{it} + p_{jt}) l_{jit} \Big) \\ - \sum_{g=1}^{G} y_{git} \sum_{p=1}^{P} e_{p,git} (d_{pt} - t_{pit}) \Bigg) - sd_{tr} \Bigg] \tag{4.10}$$

with

$$DF_t = \frac{1}{(1+r)^{\frac{t*TS}{8760}}}$$

the discount rate which converts future costs and benefits to its net present value, as explained in section 3.3. The cost of system development at time t is denoted by sd_t.

Formula (4.11) describes the socio-economic surplus aggregated for all regions $r \in R$.

$$S = \sum_{t=0}^{T} DF_t \Bigg[TS \sum_{i=1}^{I} \Bigg(\sum_{c=1}^{C} \Bigg(D_{cit} v_{cit} - \sum_{d=1}^{D} u_{cdit} V_{cdit} \, f_{cit}^{m} \, f_{cit}^{n} \Bigg) - (D_{it} - u_{it}) \mathrm{c_{TSO,it}} - \mathrm{C}_{TSO,it} \\ - \frac{1}{2} \sum_{i=1}^{I} \sum_{j \in J_i} a_{ijt} - \sum_{g=1}^{G} \big(c_{GEN,git} y_{git} + C_{GEN,git} \big) \\ - \sum_{g=1}^{G} y_{git} \sum_{p=1}^{P} e_{p,git} (d_{pt} - t_{pit}) \Bigg) - sd_t \Bigg] \tag{4.11}$$

System development decisions are assessed by comparing the surplus S (or S_r depending on the geographical scope) with and without the specific system development decision. Note that a system development decision, such as adding a new transmission line, has an effect on all aspects of socio-economic surplus: prices p_{it}, asset management costs a_{ijt}, pollutant emissions $e_{p,git}$, generation dispatch y_{git} (and thus congestion costs), interrupted load u_{cdit}, etc.[11] System development decisions that increase surplus – i.e. the benefits are higher than the cost of system development sd_t – can be

[11] See Appendix 1.

The research leading to these results has received funding from the European Union
Seventh Framework Programme under Grant Agreement No 608540.

implemented, preferably, in the order of highest added value to surplus. In addition to changing surplus, system development decisions also alter the surplus of the different stakeholder groups (consumers, producers, TSO and government).

Consumer surplus

$$\begin{aligned} S_{CONS,r} = \sum_{t=0}^{T} DF_t \Bigg[TS \sum_{i \in I_r} \Bigg(\sum_{c=1}^{C} \Big(D_{cit} v_{cit} - \sum_{d=1}^{D} u_{cdit} V_{cdit}\, f_{cit}^{m}\, f_{cit}^{n} + R^{u,TSO}{}_{cit} \Big) \\ - D_{it} p_{it} (1 + x_{it}) - (D_{it} - u_{it}) TT_{it} (1 + x_{it}) \\ - \sum_{g=1}^{G} y_{git} \sum_{p=1}^{P} e_{p,git} (d_{pt} - t_{pit}) \Bigg) \Bigg] \end{aligned} \tag{4.12}$$

Producer surplus

$$S_{PROD,r} = \sum_{t=0}^{T} DF_t \Bigg[TS \sum_{i \in I_r} \Bigg(\sum_{g=1}^{G} \Big(\big(p_{it} - (c_{GEN,git} + t_{\text{pit}})\big) y_{git} - C_{GEN,git} \Big) + f_{it} \Bigg) \Bigg] \tag{4.13}$$

TSO surplus

$$\begin{aligned} S_{TSO,r} = \sum_{t=0}^{T} DF_t \Bigg[TS \sum_{i \in I_r} \Bigg((D_{it} - u_{it})(TT_{it} - c_{\text{TSO,it}}) + \frac{1}{2} \Bigg(\sum_{j \notin I_r} (p_{it} - p_{jt}) \cdot l_{jit} \Bigg) - R^{u,TSO}{}_{cit} \\ - C_{TSO,it} - f_{it} - \sum_{i=1}^{I} \sum_{j \in J_i} a_{ijt} \Bigg) - sd_{tr} \Bigg] \end{aligned} \tag{4.14}$$

Government surplus

$$S_{GOV} = \sum_{t=0}^{T} DF_t \Bigg[TS \sum_{i=1}^{I} \big(D_{it} p_{it} x_{it} + (D_{it} - u_{it})(TT_{it}) x_{it} \big) \Bigg] \tag{4.15}$$

4.2 Data requirements

In order to conduct the SEIA as sketched in the formal presentation in section 4.1, extensive data are needed: a numerical value is needed for every variable and parameter, over all nodes, regions and time periods. In this section, data requirements are listed for the assessment of socio-economic surplus (section 4.2.1), i.e. for the SEIA from a system perspective. Furthermore, additional data necessary to assess stakeholder specific surpluses within a single-region and a multi-region setting are highlighted (section 4.2.2). The main difference between these levels of assessment is that for the evaluation of a situation with respect to socio-economic surplus only those benefits and costs passing the system border (cf. Figure 3.1) have to be accounted for, whereas the consideration of stakeholders' surpluses requires that stock is taken of transfers between these stakeholders (groups), in addition. Similarly, in the multi-region framework, transfers within and between the respective regions should be assessed. Data needs

The research leading to these results has received funding from the European Union
Seventh Framework Programme under Grant Agreement No 608540.

are listed irrespectively of any sources. These may be e.g. model outcomes, measurements, observations or surveys. The availability of necessary data to TSOs is discussed in section 4.3.

4.2.1 Assessment of socio-economic surplus

Table 4.1 lists the type of data needed for the assessment of socio-economic surplus, i.e. SEIA from a system perspective. In most categories, these can be differentiated in quantities and associated prices or monetary evaluation.

Table 4.1 Data needs for the assessment of socio-economic surplus

Quantity inputs	Value inputs
• Electricity demanded ($\boldsymbol{D}$)	• Value of served load (v)
• Energy not supplied ($\boldsymbol{u}$)	• Value of lost load (V)
• Demand and supply elasticities *)	
• Type and quantity of TSO investments, asset depreciation (input to $\boldsymbol{sd}$)	• Corresponding per unit costs (input to sd)
• Maintenance actions (input to $\boldsymbol{a_{ij}}$)	• Corresponding per unit costs (input to a_{ij})
• Type and quantity of ancillary services (input to $\boldsymbol{f}$)	• Direct associated costs (input to f)
• Generation fuel input (input to $\boldsymbol{c_{GEN}}$)	• Fuel prices (input to c_{GEN})
• Other generator variable inputs (input to $\boldsymbol{c_{GEN}}$)	• Corresponding per unit costs (input to $\boldsymbol{c_{GEN}}$)
• Operation input (input to $\boldsymbol{c_{TSO}}$)	• Corresponding per unit costs (input to c_{TSO})
• Type and quantity of generation investment, asset depreciation (input to $\boldsymbol{C_{GEN}}$)	• Corresponding per unit costs (input to C_{GEN})
• Emissions of pollutants not yet internalized (input to $\boldsymbol{e_p}$)	• Corresponding monetized value of social and environmental damage (input to c_p)
• Electricity flows to/from other regions ($\boldsymbol{l_{ij}}$)	• Electricity prices (p_i)
	• Interest rate for discounting (input to DF)

*) Despite their placement in the "Quantity inputs" column, demand and supply elasticities are dimensionless parameters that can neither be classified as quantity nor value inputs.

The value of lost load is a central value in the socio-economic analysis. Due to the fact that it is usually much higher – typically by two orders of magnitude – than the electricity price, it can impact an assessment despite low quantities of energy not supplied. The VOLL can be differentiated with respect to dimensions such as consumer groups, time, duration and location. For the assessment of intertemporal decisions, the moment of service interruption can be accounted for by differentiating between seasons, time of the week and/ or day and the duration of the interruption [2], [11]. In case an assessment is to highlight distributional implications of decisions, specifying the VOLL for different consumer groups, countries and/ or regions could be helpful [2], [19].

The way costs and benefits are taken into account depends on the preferred methodology of the assessment (discounted or annualised costs and benefits). This is especially important for the treatment of investment costs. For the methodology chosen in the formal presentation in section 4.1, the

The research leading to these results has received funding from the European Union
Seventh Framework Programme under Grant Agreement No 608540.

calculation of net present values, information on interest rates and asset depreciation ranges is required. In principle, these may vary for different countries involved.

For the consideration of operational and maintenance costs, it is important to shed light on the way they accrue. For example, eventual dependencies on events such as the number of start-ups of power plant units or dependencies on states such as utilization of transmission lines have an influence on cost structures.

Another issue with relevance for TSO costs has already been raised when discussing the formal representation of TSO surplus in section 4.1.1, namely the consideration of variable TSO costs such as costs for ancillary services. For the calculation of the socio-economic surplus only direct costs incurred by the TSO from an action as such shall be taken into account whereas payments that are transfers to or from other stakeholders within the system boundary (e.g. payments for transmission services or compensation for energy not supplied) should not be accounted for. These are only relevant when calculating stakeholder (group) specific surpluses.

4.2.2 Assessment of multiple stakeholder groups and distributional implications

For the disaggregation of the socio-economic surplus for different stakeholder groups, more detailed data compared to those derived above are needed (cf. Table 4.2). The general rule is to further consider all transfers between stakeholder groups. Therefore, regional electricity prices as well as prices for the provision and activation of ancillary services and demand response measures with associated quantities are required. The granularity depends on the objective of the computations and may range from (quarter-) hourly prices for assessing short-term actions to monthly prices frequently sufficient to assess measures related to longer time horizons. Transfers for transmission and flexibility services depend on regulatory rules on procurement and provision and on cost pass through.

Table 4.2 Additional data needs for the assessment of stakeholder surpluses

Quantity inputs	Value inputs
• Electricity traded	• Electricity wholesale prices
• Electricity transmitted	• Transmission tariffs
• Energy not supplied	• Compensation for end-consumers
• Flexibility services contracted and delivered	• Corresponding prices
• Reserves energy: power contracted and delivered	• Reserve prices (for provision and delivery)

As noted in section 4.1.1 some of these inputs will vary depending on the regulation in place. For example, compensation for interruptions to end-consumers varies between regulatory jurisdictions.

4.2.3 Assessment of multi-region settings

To calculate the overall socio-economic surplus within a multi-region setting, data requirements are equivalent to those indicated in section 4.2.1. In case different regions are to be compared with respect to regional socio-economic surpluses, it is necessary to include imports and exports in the assessment. Therefore, electricity prices in each region are needed. Moreover, in order to assess distributional implications for stakeholder groups within a multi-region setting, rules on how to distribute congestion rents between TSOs need to be specified and taken into account.

The research leading to these results has received funding from the European Union
Seventh Framework Programme under Grant Agreement No 608540.

4.3 Input data collection issues

4.3.1 Data and parameter approximation

The availability of data inputs needed for a SEIA will vary between countries and regions and collection of data can be a demanding task requiring careful preparation.

In general, the level of detail by sectors, time frame, regions, etc., of the SEIA will depend on data availability. Data will typically need to be procured from various sources:

- In the GARPUR context, all power system quantity data in the first columns of Table 4.1 and Table 4.2 will come from simulations of the power system in other modules.
- Direct costs for the various TSO activities need to be estimated based on TSO-specific data.
- Value of served load can be approximated by the consumer price of electricity.
- Value of lost load: see section 4.3.2 for a discussion of this issue.
- Generation costs need to be estimated based on fuel prices, other input costs (including costs of emission permits) and information on the composition of generation technology in each region, as well as investment costs, for the case of system development.
- Wholesale electricity prices are simulated by a separate market module. Such a module can vary greatly in sophistication; its development lies outside the scope of this report, but in its simplest form prices would be simulated by marginal generation costs in each price area. In some countries there exist sophisticated market models that can potentially be integrated into a SEIA using the GARPUR methodology.
- Transmission tariffs and per-unit compensation to electricity consumers for energy not supplied will depend on regulation in place in each region.
- Unit costs of social and environmental damage not internalised in generation costs need to be found in external sources such as IPCC reports for the case of CO2 emissions.
- Prices of flexibility services and reserves have to be modelled separately or approximated, e.g. by tying them to generation costs or electricity prices.
- The interest rate for discounting is that appropriate for socio-economic cost-benefit analysis, usually called the *social discount rate*. For practical purposes, the discount rate can be taken to be zero on the shortest time horizons and it is only in the system development context that discounting is appropriate. While approaches to estimating the social discount rate vary, it is common to use the after-tax rate on long-dated government bonds in the country in question as an approximation. In the GARPUR context, however, it seems reasonable for TSOs to use the social discount rate recommended by ENTSO-E for the evaluation of system development projects [8].[12]
    - Importantly, if the SEIA is performed in nominal terms – i.e. nominal prices are simulated for each time period – a nominal (social) discount rate must be used. Conversely, if the analysis is done in real terms – i.e. all prices are taken to be deflated by a general price index – a real interest rate must be used.

[12] In the currently valid ENTSO-E Guideline for Cost-Benefit Analysis this is not a fixed rate, but rather an interval ranging from a “risk-free” rate to the “highest cost of debt observed in the countries financing the project” [8]. The discount rate employed will therefore vary from country to country. A draft for a revised guideline, circulated for public consultation, proposes a common *real* rate of 4% as well as a lifetime of 25 years and zero residual value [37].

The research leading to these results has received funding from the European Union
Seventh Framework Programme under Grant Agreement No 608540.

The most demanding assessments in terms of data inputs are likely to be those for system development, where long-term scenarios will have to be generated for all variables. Typically, several scenarios will be generated, varying assumptions on the most important inputs.

4.3.2 Estimating VOLL

A variety of methods has been utilized to obtain empirical estimates of costs due to electricity interruptions (VOLL). These methods can be grouped into three broad categories [20], see also [21]:

- Indirect analytical evaluations
- Case studies of blackouts
- Customer surveys (Direct worth and stated preference).

Among these, customer survey methods are the most common approaches to estimate costs of interruptions. The state of the art on survey methodologies is presented in [10], [22] and advantages and disadvantages of the different methods are discussed.

In the literature, VOLL cost estimates mean different things as they are based on different methods for estimating unit costs. Whereas, e.g., in [12], the VOLL estimates are reported as normalized interruption costs for different customer sectors, the VOLL estimate is derived as an aggregate measure based on the mix of customers in a certain area in [20]. In the latter case, the VOLL represents the system specific cost for the particular area and not the generic unit costs per customer sector (see e.g., [20]).

Many customer surveys and cost studies are performed around the world over years (see e.g. [10], [11], [12], [19], [20], [22]), using more or less the same approaches, although different content of questions, different cost estimation methodologies, etc. The interruption cost data derived based on the customer surveys usually cover broad customer categories such as Industry, Commercial, Public Services, Agriculture and Households. Customers are asked to estimate costs of varying duration typically for a worst case scenario (reference time). Questions regarding energy shortage (rationing) situations or High Impact Low probability (HILP) events, e.g. if a wide-area is affected by interruptions and for very long durations, are not commonly included.

The cost data obtained through customer surveys are often regarded to be an approximation of the total socio-economic cost of interruptions [23]. At least the costs can be seen as a lower bound for the total socio-economic interruption cost. Similarly, interruption costs in HILP events can be estimated based on the same cost data for the often much longer interruption durations than for the more frequent, ordinary events, and then be regarded as a lower bound for the socio-economic interruption cost of HILP events.

To summarize, interruption costs (VOLL) are already widely used as important information about the valuation of reliability and used as basis in decisions regarding the reliability of supply. This is a fact, even if the cost data not necessarily are comparable for various reasons. There is a large variation in cost data from one country to another as shown by the examples given in [10], [20]. It can be expected that the interruption costs will vary between countries due to differences in factors such as sectorial composition of electricity consumption, power demand, dependency of electricity in the economy, by season etc. Thus, data from one country are not necessarily transferrable to another country. Differences in cost estimates are also due to different cost estimation methods, and different normalization factors (discussed e.g., in [12]). One should therefore be careful in comparing different cost estimates between different studies.

The research leading to these results has received funding from the European Union
Seventh Framework Programme under Grant Agreement No 608540.

The Council of European Energy Regulators (CEER) has set out European guidelines in the domain of nationwide studies on estimation of costs due to electricity interruptions and voltage disturbances, recommending that "National Regulatory Authorities should perform nationwide cost-estimation studies regarding electricity interruptions and voltage disturbances". Applying these guidelines would contribute to yielding comparable and consistent VOLL data among the European countries.

When there are no available data in a country or region, it is possible to use data from a different country or region scaled by purchasing power parity coefficients. It might be necessary first to convert the data (normalized data, unit costs) to the same form, e.g., €/kW or €/kWh. Also, it might be necessary first to recalculate the normalized data using the same type of normalization factor, e.g. interrupted power at a certain time, energy not supplied for a given interruption scenario, or annual electricity consumption. In [20], such a comparison is made of data between countries using the exchange rate (ER). As stated in [20], using the exchange rates can be quite misleading as it may not reflect accurately the value of reliability in the country in question. It might be a more meaningful approach to use purchasing power parity (PPP). In this approach, the prices of goods and services are internationally arbitraged so that the cost of a good is the same in all countries when measured in terms of a common currency [20]. A comparison is given in [20] using the two approaches ER and PPP for three different consumer groups and three countries. The OECD regularly publishes estimates of PPPs on its website [24].

The research leading to these results has received funding from the European Union
Seventh Framework Programme under Grant Agreement No 608540.

5 ROADMAP FOR FURTHER DEVELOPMENT

This report has presented a detailed implementation of the socio-economic impact assessment methodology developed in [2]. The implementation has a firm basis in economic theory and empirical research but, necessarily, it takes the GARPUR context into account; the overarching objective is to formulate the implementation, so as to allow for adaptation of the SEIA methodology in the numerical models and applications within the GARPUR project. There are a number of aspects that could be developed further in future research, progressing beyond the current GARPUR project. This chapter touches upon a few such issues. The chapter also discusses how the methods developed herein could be developed further in order to bring them into general practice by TSOs.

5.1 Further development of models and data

A key issue to consider in future research is better integration of the modelling of socio-economic aspects and the modelling of the power system. In the present GARPUR approach the power system is largely modelled separately, without “feedback” effects due to behavioural responses of electricity consumers and suppliers. This implies that the SEIA is mostly restricted to computing costs and benefits related to volumes simulated by a power system module. In particular, the implementation implicitly assumes that behaviour of market stakeholders is constant, i.e. does not change with changing market variables such as the reliability level, electricity prices and taxes.

As discussed in detail in [2], the SEIA framework can be extended in order to analyse and anticipate possible responses of electricity market stakeholders to changing market variables and to integrate these responses in the SEIA. Ideally, electricity market prices and power system volumes (quantities) would be determined simultaneously in a single module with interaction between the two types of variables. In effect, this would involve integration of sophisticated market models such as [25], [31], [32], [33] with the detailed power system simulation models employed by TSOs. The dimension of reliability is, however, not a feature in typical market models and needs to be developed. Inevitably, this would imply even greater demand for computing resources than is the case in the present state-of-the-art models (including GARPUR models).

Future research also needs to be directed towards the building blocks of electricity market models, in particular those related to reliability. Research into the behavioural response of market participants to changes in reliability is still at an early stage. Reference [2], however, developed some models of consumer response to changes in reliability. It was shown, *inter alia*, that the benefit from consumption of electricity and the interruption costs could change with both electricity price and reliability level. When demand increases or decreases in response to a changing price or reliability level, the remaining demand will have a different value of lost load and consumer surplus. This has a potential impact on the outcome of the SEIA. To our knowledge little or no empirical research exists on such aspects of the electricity market so implementation is premature. A limiting factor for empirical research into this area is the availability of data on consumer response to changes in reliability, which seem to be scarce or even non-existent. Clearly, to improve this situation data would have to be collected.

A considerable body of empirical research exists on demand for electricity in relation to price. Based on that research we have recommended that demand be considered inelastic to price except (possibly) for long-term horizons, in particular for system development. Technological change, however, has the potential to change this view: demand response is expected to increase in the future due to the introduction of smart meters and smart appliances. This, however, mainly shifts demand to other hours and so would tend to increase the real-time price elasticity of demand.

The research leading to these results has received funding from the European Union
Seventh Framework Programme under Grant Agreement No 608540.

Economic research has also been directed towards competitive and strategic responses of electricity market consumers [22][26], producers [27], and even TSOs [28][29] and governments [30]. A body of research exists, heavily tilted towards theory. For implementation of such aspects empirical validation of the models involved, as well as empirical estimation of parameters is needed. Again, availability of relevant data tends to be a limiting factor.

The research agenda outlined here is a natural continuation of the work done in the GARPUR project. This research needs to be firmly grounded in TSO practice to be successful and useful in terms of being implemented in actual operations. It is therefore best done as a collaborative effort between research institutions and TSOs, where the latter can draw on their experience, source data and collaborate on the research effort as such. It would also be desirable to bring the insights and perspectives of electricity market regulators to bear.

5.2 Research supporting general adaptation of the SEIA

GARPUR is a research project and the socio-economic impact assessment methodology – even if implemented for the models developed within GARPUR – still needs further development to be sufficiently accessible to be brought into general practice by TSOs. An important part of this is the integration of the socio-economic impact assessment methodology with the work currently underway in GARPUR on upgrading reliability management in operational planning and system operation, asset management and system development. Collection of data required to perform SEIA is an integral part of this work.

The pilot studies performed within the GARPUR project – in particular, those done in real-life TSO settings – will no doubt be helpful as examples of how to use the SEIA in practice. Beyond GARPUR, a wider range of case studies executed by TSOs and/or regulators would further help establish a practice of executing a SEIA and to identify where the difficulties in application lie and how to resolve them.

Full adoption of the SEIA methodology would come through its inclusion into handbooks and guidelines for TSOs. This could, for example, happen through their implementation into future editions of documents such as the ENTSO-E Guideline for Cost-Benefit Analysis of Grid Development Projects.

The research leading to these results has received funding from the European Union
Seventh Framework Programme under Grant Agreement No 608540.

6 REFERENCES

[1] GARPUR Consortium, GARPUR – Generally Accepted Reliability Principle with Uncertainty modelling and through probabilistic Risk assessment 2013, EU Commission.

[2] GARPUR, "D3.1 Quantification method in the absence of market response and with market response taken into account", 2016.

[3] BSI British Standard Institution. PAS 55-1: Asset Management. Part 1: Specification for the optimized management of physical infrastructure assets, The Institute of Asset Management, British Standards Institution.

[4] ENTSO-E. Continental Europe Operational Handbook G Glossary. Originally a UCTE document but now available at: https://www.entsoe.eu/publications/system- operations-reports/operation-handbook/

[5] ENTSO-E. Network Code on Operational Planning and Scheduling. 24 September 2013. Available at: https://www.entsoe.eu/major-projects/network-code-development/operational-planning-scheduling/

[6] IEC International Electrotechnical Commission. Electropedia: The World's Online Electrotechnical Vocabulary. Available at: http://www.electropedia.org/.

[7] ENTSO-E. Supporting Document for the Network Code on Operational Security. Available at: https://www.entsoe.eu/fileadmin/user_upload/_library/resources/OS_NC/130924- AS-NC_OS_Supporting_Document_2nd_Edition_final.pdf.

[8] ENTSO-E. Guideline for Cost Benefit Analysis of Grid Development projects. 14 November 2013. Available at: https://www.entsoe.eu/Documents/SDC%20documents/TYNDP/ENTSO-E%20cost%20benefit%20analysis%20approved%20by%20the%20European%20Commission%20on%204%20February%202015.pdf

[9] A. Smith, "An Inquiry into the Nature and Causes of the Wealth of Nations," in Library of Economics and Liberty, vol. 5th edition, Edwin Cannan, ed., 1776.

[10] M. Hofmann, H. Seljeseth, G. H. Volden and G. H. Kjølle, Study on Estimation of Costs due to Electricity Interruptions and Voltage Disturbances, 2010.

[11] L. Bjørk, E. Bowitz, C. Seem, U. Møller, G. Kjølle, M. Hofmann and H. Seljeseth, "Socio-economic costs of interruptions and voltage disturbances. Implications for regulation," Energy Norway, 2012.

[12] London Economics, "The Value of Lost Load (VoLL) for Electricity in Great Britain," July 2013. [Online].
Available: https://www.gov.uk/government/uploads/system/uploads/attachment_data/file/224028/value_lost_load_electricty_gb.pdf.

[13] GARPUR, "D4.1 A functional analysis of the System Development decision making process," 7th Framework Programme, EU Commission Grant Agreement 608540, 2015.

[14] GARPUR, "D5.1 Functional analysis of Asset Management processes," 7th Framework Programme, EU Commission Grant Agreement 608540, 2015.

[15] GARPUR, "D6.1 Functional analysis of System Operation processes," 7th Framework Programme, EU Commission Grant Agreement 608540, 2015.

[16] B. Jacobs, and R. Boadway, "Optimal linear commodity taxation under optimal non-linear income taxation," *Journal of Public Economics* 117: 201-210, 2014.

[17] F.M. Baldursson, E. Lazarczyk, M. Ovaere, and S. Proost. "Cross-border exchange and sharing of generation reserve capacity", IAEE Energy Forum, Bergen Special, 29-30 2016.

[18] Baldursson, F.M., Lazarczyk, E., Ovaere, M., and Proost, S. (2016). Multi-TSO system reliability: cross-border balancing. *Energycon proceedings*.

[19] C. Growitsch, R. Malischek, S. Nick, H. Wetzel, "The Costs of Power Interruptions in Germany: an Assessment in the Light of the Energiewende," EWI Working Papers No. 13/07, 2013.

[20] R. Billinton, "Methods to Consider Customer Interruption Costs", task force 38.06.01 Cigré, 2001.

The research leading to these results has received funding from the European Union
Seventh Framework Programme under Grant Agreement No 608540.

[21] GARPUR, “D1.1 State of the art on reliability assessment in power systems,” 7th Framework Programme, EU Commission Grant Agreement 608540, 2014.

[22] G. H. Kjølle, K. Samdal, B. Singh and O. A. Kvitastein, “Customer Costs Related to Interruptions and Voltage Problems: Methodology and Results,” Power Systems, IEEE Transactions on, vol. 23, no. 3, pp. 1030-1038, 2008.

[23] G. Wacker and R. Billinton, "Customer cost of electric service interruptions," Proceedings of the IEEE 77(6), 919-930, 1989.

[24] OECD, Purchasing Power Parities (PPPs) Data, Available at: http://www.oecd.org/std/purchasingpowerparitiespppsdata.htm

[25] S. Stoft, “Power System Economics,” IEEE Press, 2002.

[26] M.A. Bernstein, and J.M. Griffin, “Regional differences in the price-elasticity of demand for energy,” National Renewable Energy Laboratory, 2006.

[27] J.B. Cardell, C.C. Hitt, and W.W. Hogan, “Market power and strategic interaction in electricity networks, “ Resource and Energy Economics, 19(1-2), 109–137, 1997.

[28] T. Jamasb, P. Nillesen, M. Pollitt, “Strategic behaviour under regulatory benchmarking”, Energy Economics, 26(5), 825–843, 2014.

[29] Nordel Grid Disturbance Group (STÖRST). Nordel’s Guidelines for the Classification of Grid Disturbances. 2009; Available from: https://www.entsoe.eu/news-events/former-associations/nordel/operations/

[30] D.D. Huppmann, J. Egerer, “National-Strategic Investment in European Power Transmission Capacity”, European Journal of Operational Research, 191-203, 2015.
NordREG, “Economic Regulation of TSOs in the Nordic Countries,” 2012.

[31] K. Trepper, M. Bucksteeg, C. Weber, “Market splitting in Germany – New evidence from a three-stage numerical model of Europe”, Energy Policy 87, 199-215, 2015.

[32] S. Spiecker, P. Vogel, C. Weber, “Evaluating interconnector investments in the north European electricity system considering fluctuating wind power penetration“, Energy Economics 37, 114-127, 2013.

[33] P. Meibom, R. Barth, B. Hasche, H. Brandt, C. Weber, M. O’Malley, “Stochastic Optimization Model to Study the Operational Impacts of High Wind Penetrations in Ireland”, IEEE Transactions on Power Systems, 26, 1367-1379, 2011.

[34] ENTSO-E. “Guideline for Cost Benefit Analysis of Grid Development projects, Draft for Public Consultation”, April 2016. Available at https://consultations.entsoe.eu/system-development/cba-2-0/consult_view.

The research leading to these results has received funding from the European Union Seventh Framework Programme under Grant Agreement No 608540.

APPENDIX 1. ENTSO-E GUIDELINE FOR CBA ANALYSIS OF GRID DEVELOPMENT PROJECTS

The ENTSO-E Guideline for Cost Benefit Analysis (CBA) of Grid Development Projects [8] is the currently employed methodology for evaluating system development Projects of Common Interest (PCI) to two or more TSOs. Such projects are included in the GARPUR System Development category so the methodology in the CBA guideline is of particular interest for this aspect of the methodology developed in WP3. In particular, it can be compared to the new approach developed within GARPUR for system development projects, as presented in chapters 3 and 4 of this report; operational and asset management aspects can be conceptually related as well.

The CBA guideline involves a combined multi-criteria and cost-benefit analysis where some indicators are monetised but others are technical. Figure A1.1 shows the main categories of the project assessment methodology schematically [8].

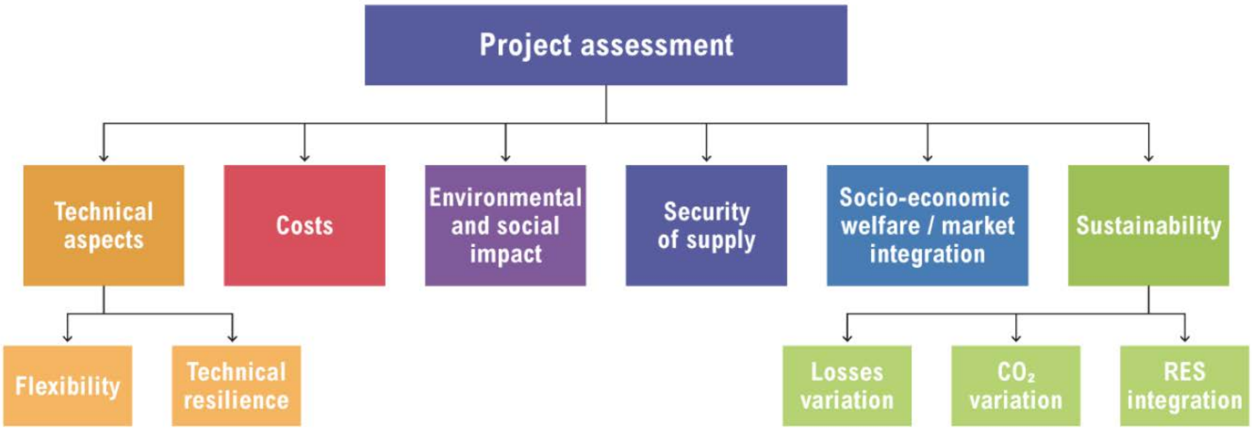


Figure A1.1 Main categories of the project assessment methodology [8]

Table A1.1 summarizes the benefit and cost categories of electricity transmission investment listed in the CBA guideline [8].

Table A1.1 Benefit and cost categories of electricity transmission investment [8]

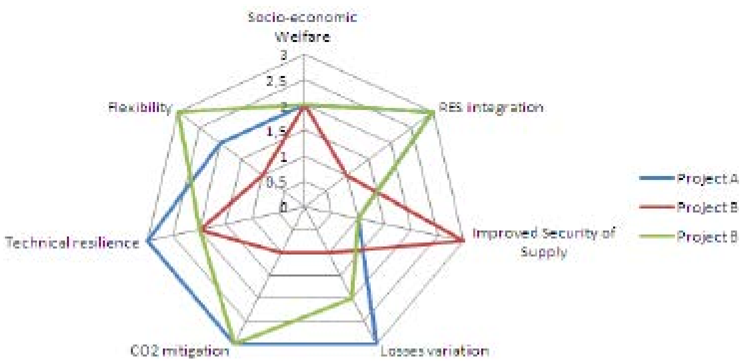
Project benefit categories	Project costs categories	Project impact on society[13]
B1. Improved security of supply	C1. Total project expenditures:	S1. Environmental impact
B2. Socio-economic welfare	Materials and assembly costs	S2. Social impact
B3. RES integration	Environmental costs	
B4. Variation in losses	Consenting costs	
B5. Variation in CO_2 emissions	Dismantling costs	
B6. Technical resilience/system safety	Operations costs	
B7. Flexibility	Maintenance costs	

[13] This indicator only takes into account the residual impact of a project, i.e. the impact after potential mitigation measures are defined and fully accounted for under C1 (when the projects becomes more precise).

The research leading to these results has received funding from the European Union Seventh Framework Programme under Grant Agreement No 608540.

The benefit categories B1, B3, B4, B5, B6 and B7 are technical and are assessed in network modelling analyses. Only B2 is an economic indicator and, despite the name it is confined to assessing welfare gains from a reduction in congestion costs due to better market integration. Note, however, that, provided the market cost of CO2 emissions are included in generation cost, category B3 is also monetised (to the extent that EU Emissions Trading System (ETS) prices reflect the correct social cost of emissions) and included in B2; B5 is a purely technical indicator. The guideline notes that projects that increase the power transfer capability may have a positive effect on competition, but such effects are only qualitatively assessed.

The main difference between the CBA guideline and the GARPUR methodology concerning system development is that cost and benefit indicators are monetised in the latter. Thus, project benefit categories B1, B3, B4 and B5 are all monetised in the GARPUR approach. Figure A1.2 illustrates overall assessment and comparison for three projects using the ENTSO-E CBA methodology. It should be emphasised that the socio-economic welfare indicator used by ENTSO-E only includes a part of the welfare concept as used in GARPUR.



	Project assessment									
Criteria	Grid Transfer Capability Increase	Socio-economic Welfare	RES integration	Improved Security of Supply	Losses variation	CO2 mitigation	Technical resilience	Flexibility	Social and environmental Impact	Project costs
	MW	M€/year	MWh/year	MWh/year	M€	Mt				M€
Project A	1000	150	500			0,5	+++	++		650
Project B	500	30		3000	20		++			25
Project C	800	225	3000		10	1	++	+++		150

Figure A1.2 Illustration of overall assessment using the ENTSO-E Guideline [8]

ENTSO-E has developed a new version of the CBA guideline [8] which is in a consultation and review process at the time of this writing [34]. The main novelty in that version is that *Security of Supply* is now assessed by two means: *System stability*, which is “the ability of a power system to provide a secure supply of electricity under extraordinary conditions and to withstand and recover from extreme system conditions” and is measured by technical analysis of extreme cases, and *Adequacy to Meet Demand*,

The research leading to these results has received funding from the European Union
Seventh Framework Programme under Grant Agreement No 608540.

which measured by the impact of the grid development project on Expected Energy not Served; this measure may be monetised as “additional information” rather than for inclusion in an overall social surplus measure. The new version therefore brings the ENTSO-E guideline closer to the approach proposed in GARPUR, but there are still important differences.