CERRE CENTRE ON REGULATION IN EUROPE

CONFIDENTIAL

Investments on transport infrastructures for natural gas and electricity

Towards a comprehensive conceptual framework to assess their impact on social welfare

A CERRE study

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Executive summary

The increasing dependence on remote sources of natural gas and the growing demand for energy in Europe – together with security of supply and environmental concerns – call for a wave of investments in energy infrastructures in most European countries. Furthermore, the development of an integrated pan-European transportation system – both in gas and electricity – is seen as a necessary condition for the development of competition within the European wholesale energy markets.

These network upgrades are to be planned in the context of liberalized markets characterized by high degrees of uncertainty. In order to govern network development, the European regulation points at a hybrid system where System Operators (SO) and Regulators will have to coordinate their planning activity with the developments of the market, in terms of demand, supply, system adequacy and merchant investments in energy infrastructures. Member States will enjoy wide discretion on how to set up the decision-making process and allocate the risks of the new investments. In this respect, the default framework in the Directive is the traditional one, which places all the risks on final customers, who bear the cost of all the investments selected by the SO and approved by the Regulator, irrespectively of their actual use and usefulness. However, merchant infrastructures will also be allowed and, particularly in the gas sector, the development of new transmission pipelines will have some market-based features.

In spite of the priority assigned to the deployment of a coordinated investment plan, the methodological framework which is used to assess infrastructural upgrades in the EU is still largely undetermined. The available literature often focuses on specific issues, such as competition or system adequacy, without putting all possible costs and benefits in a unified framework.

The Report addresses this crucial topic, providing a comprehensive methodological framework in order to assess the impact of transmission upgrades, covering also the elements of the regulatory and organizational framework that may directly impact the effectiveness of the investment selection methodology, ranging from the definition of transportation rights, to transmission tariff design, to trading arrangements.

Further, in a context in which investment decisions are still taken – to some extent – on a national basis, the Report addresses the issue of how the investment costs could be shared among different countries.

The methodology we propose allows for the assessment of the impact on social welfare of any transmission upgrades, by simulating the market outcome with or without the new infrastructure. Moreover, environmental externalities and security of supply concerns are taken into account in the simulation and assessment process.

Within a unifying methodological framework, we have considered two different approaches to take into account the distinguishing features of the gas and electricity sectors. For the electricity sector, the assessment is mainly based on a Security Constrained Optimal Dispatch Model, which simulates a cost-effective equilibrium between supply and demand. For the gas sector the assessment is also based on a cost effective simulation of the market equilibrium, but with a different approach. The difference between electricity and gas stems from the high degree of uncertainty related to the model inputs. For instance, predicting gas flows across a central European country requires assessing the procurement sources of all the surrounding countries and, ultimately, how supplies to Europe will be shared among the main producers. Moreover, the relation between production costs and market prices is particularly complex and different estimations might lead to different results. To overcome these issues, we propose a hybrid decision-making process, designed in such a way that the SO and the Regulator can extract as much information as possible from the market. In this hybrid institutional setting, the assessment of the value of the gas transmission upgrades is based on the availability of market investors to take on some of the corresponding risk.

Our analysis is based on the assumption that the SOs are "benevolent", i.e. they maximise the relevant notion of social welfare without pursuing any private agenda. This rules out of our analysis any issue related to the incentives for the SO to select the optimal set of network upgrades. Having ruled out any SO-incentive issues, we consider regulatory systems and investment selection methodologies that place no risk on the SO. In fact we see no basis to place risk on the SO if not within the context of an incentive-based regulatory scheme. As a consequence, the alternative approaches that we have considered differ in the way they split the investment risk between final customer and the transmission network users.

Adapted Cost Benefit Analysis

The prevalent role of the central decision-making by the system operators and the industry regulators, within the European context, makes the assessment of the costs and of the benefits of network upgrades crucial.

The cost-benefit analysis (CBA) is a set of standard analytical tools applied by local, national and international development agencies to evaluate policies, programmes, projects, regulations, and infrastructural investments. A key concept underlying CBA is that observed prices may not provide the correct measure of a project's contribution to social welfare and investment decisions taken on such basis may lead to a socially undesirable outcome. The market process may fail to result in welfare maximizing production and investment decisions due to market or regulatory failures. The way to address those imperfections in the standard CBA is to apply corrective factors to the input and output prices, in order to reflect the real costs and benefits respectively incurred by and accruing to society.

We propose to adapt the standard CBA methodology in order to take into account the specificities of the electricity and gas sectors, as well as the European economic and institutional environment. In Europe, the energy regulators' mandate is typically narrower than the one assumed in the standard CBA. The regulator's objective function is typically limited to maximizing the total surplus created in the industry and not in the entire economy. Other institutions and policies address issues such as growth, inequality, employment etc. On the other hand, the way the surplus generated in the industry is split between consumers and suppliers is highly relevant in the regulator's agenda. Much of the regulator's action relates to preventing the exercise of market power, not only because of its adverse effects in terms of total surplus generated in the industry but, above all, because of its welfare distribution implication. Finally, environmental sustainability objectives impact on the regulator's decisions but are not set by the regulator; from the regulator's point of view they can in a sense be interpreted more as constraints than as objectives.

These features result in three broad methodological implications. First, the proposed methodology refers to a welfare function whose scope is limited to the gas or the electricity industry. This means, for example, that our analysis does not assess the impact of the energy transmission infrastructure upgrades on the surplus created in the wire and pillar industries. Second, we take the actual investment costs and the current prices for the outputs to represent the correct economic values. Third, the financial analysis, central in the standard CBA, does not play an important role in our setting. In fact, in a central planning framework, investment costs are passed on to the electricity and gas consumers via tariffs. Therefore, once the desirability of the investment is assessed based on the comparison between benefits and costs, financial issues are addressed in the tariff-setting process.

The transmission network is an input to electricity and gas supply. For that reason, assessing the value of transmission upgrades requires estimating the changes in the market outcomes induced by the additional transmission capacity. The methodology to assess the impact of the network upgrades on the market outcome is different for the electricity and for the gas sector.

Electricity transmission investments

A significant part of the benefits from transmission upgrades results from their impact on generation and ancillary services' costs. However, other types of benefits should be taken into account as well when assessing the welfare impact of a new transmission line. First of all, the infrastructural upgrade is likely to improve the system adequacy. Other benefits may arise from the possibility of connecting and dispatching a higher quantity of renewable sources, as well as from a reduction of Green House Gas (GHG) emissions. All these types of benefits are typically interdependent and should be assessed simultaneously.

We propose to base the assessment of the value of electricity transmission investments on a Security Constrained Optimal Dispatch (SCOD) model. The SCOD allows to forecast the wholesale market outcome "with and without" the proposed network upgrade and assess most of the effects of the transmission upgrade simultaneously, ranging from electricity prices, to network losses, from emissions to system security. Depending of the specific features of the implemented model, some effects may have to be assessed partially off-model. Typically the assessment of the effects of the network upgrades on the generator's market power and on system reliability require some off-model analysis.

SCOD allows for a clear identification of the hypothesis stated in terms of the evolution of installed generation capacity under different scenarios. Such modelling can be done applying optimization techniques to the constrained optimal dispatch problem. Power injections of generators are chosen to minimize the total generation costs to meet demand, while satisfying the security constraints on the resulting power flows.

The assessment is carried out with reference to a market mechanism that determines the most efficient use of the available network resources in a short time frame, typically hour-by-hour. In that setting transmission rights are allocated "implicitly", within the process that determines the minimum set of costs that generators will produce.

The SCOD can be used in order to simultaneously assess the following impacts of the network upgrades:

- Changes in generation costs;
- Changes in ancillary service costs;
- GHG emissions reduction;
- Changes in the amount of renewable generation.

Other benefits, such as reliability and reduced losses, should be assessed independently, at least in an initial phase.

In our proposed approach, the methodology to assess the cost of the network infrastructure does not depart from the methodology that a private investor would follow to forecast the cost of a large technical infrastructure, as in the adapted CBA.

Accounting for security of supply in the electricity sector

Security of supply, in the electricity industry, depends on the availability of primary sources for electricity production and on an adequate level of installed generation capacity. Security of supply objectives are reflected in the SCOD assessment, as they impact the evolution of the generation capacity installed in the system, which is an input to the SCOD model.

Accounting for market power in the electricity sector

In the SCOD model the level of the generators' price bids used has been assumed to be reflective to the generators' variable cost. However, generators may enjoy market power, i.e. they may have the ability and the incentive to set prices, deviating from competitive levels. Binding transmission constraints within a single coordinated market result in fragmented geographic sub-markets, in which market concentration is often higher than at the broader market level. Thus, transmission upgrades may generate benefits by expanding geographic sub-markets and thus decreasing the generators' market power.

We propose the assessment of the impact of transmission expansions on market competition off-model. Namely, by: a) calculating the measures of market power of each market player and b) applying bid mark-ups that reflect the market power measured by those indicators.

Gas transmission investments

The general framework for a cost-benefit analysis of a gas transmission investment does not conceptually differ from the one discussed for the electricity network investments. In particular for gas as well as for electricity the value of a transmission upgrade is, in general terms, the net surplus of the additional transactions that are made feasible by the upgrade. Therefore assessing the value of a network upgrade requires identifying the set of additional transactions with the highest net surplus that can be supported as a result of the upgrade. However, the specific economic and institutional features of the gas industry require significant departures from the methodology developed for electricity.

The first specific feature of the gas industry is that most of the gas consumed in Europe is imported from non-European countries. Therefore, if the SOs and the regulators act on behalf of the European citizens, the welfare notion relevant for the assessment of the gas transmission upgrades should not include the producers' profits. In practice that means that the cost-side of the welfare function should not reflect the gas production costs, but should reflect the gas procurement price assessed at the European borders.

The second feature is that long-haul transmission infrastructures are usually idiosyncratic to investments in gas production. The merchant regime appears the most suitable for that type of infrastructure, as investors need to control access to the transmission capacity to reap the benefits of their investment in production over the relevant time frame. We therefore expect the merchant model to feature prominently in the gas industry in the future.

The third feature specific to gas relates to the trading arrangements. The liberalization of the European gas markets has not yet delivered its full impact. That depends on various elements, including the fact that Third Party Access and the Use It Or Lose It (UIOLI) provisions on the existing international pipelines are not yet fully effective. In addition, wholesale spot gas (and transmission capacity) trading within Europe are still limited, because of contractual and/or regulatory frictions inherited from the past. Improvements to those areas of the regulatory framework may dramatically modify the assessment of the opportunity of some transmission upgrades. Therefore the value of additional transmission capacity cannot be assessed under the assumption that the regulatory framework, as we see it now, is stable.

Finally, forecasting the future transactions of gas in order to assess the market value of gas transmission upgrades is very difficult, given the lack of transparency and the nature of the transactions. Predicting the electricity production (and cost) at each location is – at least conceptually – relatively easy, once one has predicted the evolution of demand and of the installed generation capacity. On the contrary gas transactions, in particular at the production level, depend on many conditions – related to the global economic and political environment – whose prediction is a risky exercise.

For those reasons the methodology for assessing the value of gas transmission upgrades must be designed in a way that allows the Planner to extract the greatest possible amount of information from the market. We have therefore developed our proposal around a hybrid institutional setting, compatible with the Directive 73/09, in which the assessment of the value of the gas transmission upgrades is based on the availability of market investors to take on some of the corresponding risk.

In the proposed hybrid framework the SO operator acts as the aggressor of the market demands for additional transmission rights. In this framework market investors bear part of the investment risk, as they commit to purchasing the additional transmission rights over a given period of time.

That methodology appears to be flexible enough to address a wide range of investment opportunities, including investments that increase the system's flexibility and investments that will mainly support so-called "transit flows", provided an adequate degree of coordination among the SOs is reached. We also discuss how investments in excess capacity, motivated by security of supply concerns would fit into our proposed methodological approach. Finally we argue that one of the advantages of the proposed methodology is that it reduces the need for arbitrary common cost allocation exercises.

Accounting for Security of supply in the gas sector

The European Regulation (994/2010) sets target levels of security that can be directly reflected in the assessment of the transmission upgrades. Members States are required to ensure that no service disruptions occur in the case that one major piece of infrastructure defaults. As far as supply standards are concerned, requirements are set to ensure the availability of supply of gas to protected customers under extreme demand conditions. Finally the Commission states in its Communication, COM(2010) 677/4, on energy infrastructures: "*Every European region should implement infrastructure allowing physical access to at least two different sources*".

Once the security targets are defined, the SO will figure out the adverse events that might threaten security of supply, like for example a failure of the main transmission infrastructures, storages or LNG terminals, or interruption of supplies from a certain country. On that basis the SO can assess if the security criteria are met, i.e. if – given the infrastructure endowment – supply to the final customers is threatened by some of the adverse events.

In the case that the security constraints are not satisfied the SO will add to the network investment plan additional transmission capacity, in order to meet the security targets at the minimum cost.

Accounting for market power in the gas sector

It is generally recognized that an increase in the transmission capacity is likely to increase competition among suppliers. Still, one has to distinguish between transmission upgrades that are conditional on a long-term supply contract (contracted transmission capacity) and upgrades that do not necessarily bring new gas. Assessing the impact on competition of the first type of investments is relatively straightforward, as the standard competition policy toolbox can be deployed in order to analyze the importing country's wholesale gas market. The impact of the additional gas imports on competition depends on the position of the importing firm that controls the incremental transmission capacity in the market and on the competitive interaction among the active wholesalers in the market. The effect of the entry of additional gas in an oligopolistic market is likely to be properly captured by (changes in) the usual concentration indices based on market shares.

For the second type of investment, instead, the assessment can be performed by measuring gas price differences amongst involved countries. If the wholesale price differences among the countries are large and steady, it is particularly important – for the purpose of predicting the competitive effects of the network upgrade – to understand why market investors are not ready to fund that investment on a merchant basis. The reasons as to why the investment is unattractive to market investors might also prevent the competition-enhancing effects of the transmission capacity increase to unfold, in case the investment took place in the "regulated" environment. For these reasons we suggest that investment decisions based on the expectation of a competition enhancing effect of the additional transmission capacity should be based on a thorough assessment of the market conditions.

Environmental externalities

New investments can bring about several external environmental effects. Whenever valuing any network upgrade it is thus important to attach a monetary value to those effects in order to assess their relative magnitude. Those effects can be produced directly by the new transmission facility (e.g. land use, electromagnetic pollution, reduction of visual amenities), or by the changes in the market stemming from the new infrastructure (e.g. increased renewable generation, reduction of losses).

We describe a methodology developed within an EC project, called ExternE, whose results are publicly available and are used by the European Commission (DG Environment) to value external costs. This methodology aims at attaching a monetary value to all external effects originating from energy related activities. In particular, ExternE permits to analyze four types of externalities:

- Geographically limited environmental externalities – the release of either substances or energy into the environmental media;
- Biodiversity loss;
- Climate change externalities – the release of GHG;
- Low probability –high damage risks.

Cost sharing

Transmission investments, besides increasing welfare, may cause a large surplus redistribution amongst geographic areas and, within an area, between generators and consumers. The scope and direction of those wealth transfers depend on each market participant's hedging position against electricity and gas price changes resulting from the network upgrades.

The first political question is whether some wealth-transfer effects of the investment should be sterilized through appropriate policy measures. Besides consideration of fairness, leaving the pre-investment surplus allocation unchanged, that would facilitate reaching consensus on the construction of positive-net-valued investments. This issue might be particularly relevant for investments whose effects are cross-border, in particular if in the exporting country the political weight of electricity price increases is higher than the political weight of increased profits obtained by the generators.

Although our discussion on how to split the cost of cross-border network upgrades is carried out with reference to the effects of the upgrades on electricity (or gas) prices in each country, our could be extended to benefits and costs that are not directly reflected in electricity (and gas) prices (indirect benefits).

We have identified at least two cases where public policies appear to reflect surplus redistribution concerns. First, the new electricity market design being discussed in France, which fixes the existing allocation of the nuclear rent between the generators and the French customers. Second, in the US, the Devers-Palo Verde No. 2 case appears to be an example of a net-positive valued investment rejected because of its (infra-marginal) surplus redistribution effects.

In the US the “beneficiary pays” principle seems well established, even though methodologies that do not link the cost allocation to any measure of the economic benefits gained by the different stakeholders are still extensively implemented. When the “beneficiary pays” principle is evoked, the cost of network upgrades are allocated to customers located in areas where, because of the upgrade, greater imports are expected to take place. This appears consistent with the view that, in the long term, the expansion of the generation capacity in the exporting areas will bring prices in the exporting countries back to the levels prevailing before the network expansion. Nevertheless, the fairness of that approach, could be questioned as the installed capacity adjustments might take a long time and massive welfare transfers would take place before the system settles to a new long-run equilibrium. The same line of reasoning appears to provide a foundation for a priority use of the congestion rents to pay for transmission upgrades.

1 Introduction

The increasing dependence on remote sources of natural gas and the growing demand for energy in Europe – despite the mitigating effect of the global economic crisis - call for a wave of investment in energy infrastructures in most European countries.

Furthermore, existing electricity and gas transportation infrastructures have been developed by former national monopolists to serve mainly national purposes. Cross border transactions were historically carried-out within the framework of relationship among "utilities". The main driver of cross-border interconnection, in particular in electricity, was security. Today the development of an integrated pan-European transportation system – both in gas and electricity – is seen, first as a necessary condition for the development of competition in the European wholesale energy markets. In most European countries the electricity and gas markets are highly concentrated; cross-border competition would play an important role in disciplining the incumbent players. This situation has been highlighted by the European Commission in the recent Energy Sector Inquiry (SEC(2006) 1724).

Finally, the development of a more integrated European electricity transmission system is said to be necessary in order to achieve the European environmental objectives, requiring exploitation of renewable sources located in remote areas. On the gas side, the development of the gas transportation system is necessary in order to increase suppliers' diversification and security of supply.

The size of the investments and the fact that – typically – much of the risk involved passes through to the end-customers via regulation, makes it necessary to deploy a transparent and robust methodology in order to assess the welfare impact of energy network investments.

As a matter of fact, decisions on the deployment of new transport capacity is often taken without the support of a clear and transparent impact assessment methodology. This has serious implications for SOs and their customers. In order to finance the requested investments, SOs have to call on capital markets, with a significant impact on their balance sheet structure and credit rating.

In developing the methodology to assess the welfare impact of energy network investments, additional challenges result from the fact that most of the new electricity and gas network projects will be inherently multi-country, either since they will directly aim at supporting additional cross-border trade or because they will generate significant network externalities across countries.

Within a unified methodology, this Report defines two different approaches to assess overall costs and benefits of network investment projects in natural gas and electricity transmission infrastructures. The proposed methodology allows assessing benefits and costs expected to result from the deployment of incremental gas transport and electricity transmission infrastructures, in terms of their impact on:

- Security of supply;
- Competition in the gas and electricity markets;
- Environmental sustainability of the energy sectors.

Assessed benefits must be compared with the expected costs for the purpose of a) selecting amongst alternative projects and b) building a priority order for the completion of the projects.

The analysis is carried out taking into account the impact of different institutional settings with respect to the deployment of new transmission infrastructures. As a matter of fact the impact of a change in transport and transmission infrastructures on competition and, ultimately, on social welfare depends on the way those infrastructures are used. The mechanisms to allocate the incremental transportation or transmission capacity made available through the investments, as well as “use it or lose it”-like clauses, might impact dramatically on the possibility for the new infrastructures to deliver benefits to market participants and, ultimately, to customers.

The Report is organized as follows: In the next chapter we will introduce the principles of the Cost Benefit Analysis, as developed by the DG REGIO. Given the broad nature of the CBA framework, chapter 3 will be devoted to discussing its adaptation to energy network investments. Moreover, this chapter will discuss the role of the cost-benefit assessment under alternative institutional arrangements governing the investment decisions. In particular, we have compared two extreme settings: the merchant setting and the central planning setting. The two following chapters, 4 and 5, present a specific methodology in order to assess the impact on total welfare of network upgrades in both the electricity and the gas sector. In order to carry out a comprehensive analysis, these two methodologies are integrated with a specific assessment of external costs as explained in chapter 6. Still, the precise assessment of the impact on total welfare of any proposed upgrade might not be enough to realize it. In fact, whenever different countries are involved, cost allocation issues might prevent a beneficial investment to be carried out: to solve this, chapter 7 addresses the issue of how these costs could be shared among different countries.

Proposed further research

This Report summarizes the findings of the first and second phases of the original Project Agreement. As envisaged with the sponsors, the conceptual framework developed at this stage could quite usefully serve as a third phase in the project. This would allow sponsors to be provided with a very concrete evaluation of the cost-benefit balance of two given investment plans, one in gas transportation in one EU member state and one in electricity transmission in another member state. Those two “new investment” scenarios would be assessed against the “As is” scenario in each sector respectively. They would also highlight areas where uncertainties on the estimation of costs and benefits are more likely to arise. Given the methodological approach proposed for the electricity sector, the transmission upgrade to be assessed would concern an electric system for which a Security Constrained Optimal Dispatch model is available. If the principle of conducting a third phase is endorsed by the sponsors, CERRE proposes to analyse an infrastructural upgrade in Belgium, making use of Elia’s model if available, and for the gas sector, a new pipeline in Germany. Both pieces of infrastructure would obviously have to be identified with the sponsors. On this basis, CERRE would then propose a budget and timetable for the completion of that third phase.

2 Cost-benefit analysis: principles and application to the European energy infrastructures

This chapter describes the Cost Benefit Analysis (CBA) methodology, an analytical tool often applied by local, national and international development agencies to evaluate policies, programs, projects, regulations, and infrastructural investments. In its typical applications, the main methodological features of the CBA are:

- The assessment of the overall benefits and costs of the project, including both direct effects – taking place in the industry where the investment is realized - and indirect effects – materializing in other industries;

- The assessment of the private benefits and costs belonging to the party that makes the investment, typically in order to assess the need to grant financial support to the project;

- Besides accounting for those external effects that are not directly reflected in the prices for the inputs and the outputs of the investment, the CBA analysis accounts for the possibility that market prices for the inputs and outputs of the investment may not be representative of the correct social values of those inputs and outputs. For example, if an investment is expected to have a positive impact on the labor market that is believed to be not internalized in current wages CBA suggests a reduction of labor costs when calculating total investments costs.

The standard CBA methodology will be the starting point of our analysis. In sections 2.1 we outline the main elements of the CBA methodology. In section 2.2 we position the methodology developed in the following chapter with respect to the standard CBA framework.

2.1 Principles, foundations and scope of CBA application

Cost-Benefit Analysis (CBA) is an analytical tool used for judging the economic advantages or disadvantages of an investment decision by weighting its costs and benefits in order to assess the welfare change attributable to it. The purpose of the CBA is to support a more efficient allocation of resources, demonstrating the convenience of a particular intervention against possible alternatives for society.

This approach is applied to all "public" investments, intended in their widest meaning. This is meant by not only projects financed by public funds or managed by public authorities, but also private investments realized within a regulated framework where tariffs are set in such a way as to cover investment costs.

CBA foundations lie in the microeconomic theory. France can claim the intellectual paternity of cost-benefit analysis: Jules Dupuit discussed the subject as early as 1844 in an article discussing the optimum toll for a bridge[1]. His concept of consumers' surplus is still adopted today in the analysis of the transmission investments. In this sphere, and also in water-resource investments, cost-benefit analysis had quite well-set traditions and applications. Its practical use, however, began with water resource development in the United States in the 1930s. Despite the theoretical connection with parts of traditional economics, it was started by engineers and its use became mandatory for public investments, first in the water sector and then spreading to other fields. In the United Kingdom the use of cost-benefit analysis came later, and was related mainly to the field of transmission, for example in order to study a new underground railway line in London. But over time the use of the CBA was extended to other sectors, such as the water and sewerage industry: currently, in England and Wales Ofwat[2] requires water services companies to include a cost-benefit analysis (CBA) in support of the five-year investment plans in order to justify their choice of specific solutions. Then, it was believed that the use of accounting prices could also be acceptable for the analysis of other projects.

[1] Dupuit, J. (1844) "De la mesure de l'utilité des travaux publics", Annales des Ponts et Chaussées, s. II, 2nd semester, pp. 332 – 375 ; English translation "On the Measurement of the Utility of Public Works", by R.COUNTRY. Barback, International Economic Papers (1952), n. 2, pp. 83-110

[2] Ofwat (The Water Services Regulation Authority) is the public economic regulator of the water and sewerage sectors in England and Wales (http://country.ofwat.gov.uk/).

In the 1970s the fusion between the welfare economics theory and the cash flow discounting principle led to the modern concept of cost benefit analysis: a system of accounts, based on data valued with “shadow” prices, that allows the calculation of “economic” performance indicators, such as the Economic Net Present Value and the Economic Rate of Return. This system made it necessary to uniform data processing methods and practices and a natural context for the application of CBA were the developing countries. A milestone in providing a synthesis to all of the concepts and expressions accumulated, was that of Ian Little and James Mirrlees, in their Manual of Industrial Project Analysis for Developing countries (1969). The book put down the methodological basis to carry out a standardized project appraisal. Building on this experience, the Guidelines for Project Evaluation (Marglin, Dasgupta and Sen, 1972), developed at UNIDO, Wien, and the Economic Analysis of Projects (Squire and Van der Tak, 1975), a World Bank reinterpretation of the Little-Mirrless contribution, followed. These works offered slightly different frameworks of analysis, but were all articulated alongside the methodology developed earlier by Ian Little and James Mirrlees.

More in detail, three approaches had been arising and were recognized worldwide, as providing coherent methods in analyzing the economic viability of public investments:

- The Harberger-Mishan method, based on “economically efficient” shadow prices, whose application, in the general market equilibrium, guarantees the most efficient resource allocation according to Pareto optimality, disregarding equity considerations;

- The Litte-Mirlees method, based on “socially efficient” shadow prices, whose application also incorporates objectives of social equality and income redistribution;

- The Tinbergen method, based on “programme indicators”, whose application measures the contribution of a project towards a set of social priorities.

Today CBA is applied in many sectors, including transmission (road, railway, port, airport), environment (water supply, waste water, solid waste), social infrastructure (child care, education, health, culture, tourism), ICT and R&D (scientific and technological parks) sectors. CBA has been also used for appraising projects in the energy sector (although mainly referred to generation and in a vertically integrated market)[3] and, as already mentioned, can be suitable not only for public-funded projects but for all interventions where the social perspective is relevant for the final decision (e.g. for regulated markets and utilities).

CBA is used for project appraisal for local, national and international development agencies and many CBA traditions have been developing worldwide[4]. In the EU policy framework CBA is a regulatory requirement[5] for major projects (those with an investment cost higher than 50 Million Euros, which is 25 for environmental projects and 10 for projects co-financed by the Instrument for pre-accession) co-funded by the European Regional Development Fund, the Cohesion Fund and the Instrument for pre-accession[6]. The Commission's decision about if and to what extent the proposed project is worth co-financing under the EU Cohesion Policy budget is informed by, among other analysis, a CBA (the DG REGIO Cba Guide is now at its fourth edition[7]).

Despite different traditions, the state-of-art on CBA methodology today offers a common set of rules, whose basics lie in the following:

- A monetary value is attributed to all the positive and negative effects of the intervention over an appropriate time horizon. These values are discounted and then summed up in order to get a net total benefit;

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[3] As a matter of example see Jenkins et al. (1999) for a practical application.
[4] As an example, see The Green Book of the British Treasury, available at: http://country.hm-treasury.gov.uk/data_greenbook_index.htm (last visit October 2010); Belli et al. (2001) of the World Bank Institute; the EIB Railpag Guide available at: http://country.eib.org/attachments/pj/railpag_en.pdf (last visit October 2010), the EIB Environmental and Social Project Appraisal Guidelines, 2006Boardman et al. (2006).
[5] See Art. 40 of Reg.1083/2006
[6] In the 2007-2013 programming period around 400 billion Euros is the budget of ERDF and Cohesion Fund in the EU27. About half of this budget is spent in infrastructure projects (5% in the energy sector).
[7] Available at: http://ec.europa.eu/regional_policy/sources/docgener/guides/cost/guide2008_en.pdf

- Overall project performance is measured by indicators, expressed in monetary values, allowing for competing projects or alternative comparability and ranking in order to assess priority;

- An incremental discounted cash flow method is applied so that a comparison is made of the scenarios with and without the project;

- The opportunity cost of resources is the key concept for measuring social costs and benefits. “Shadow” (or accounting) prices, reflecting the opportunity cost of resources, are used to correct observed market prices. In the case of non-market impacts and externalities, they are valued by means of different techniques such as the willingness to pay (and willingness to accept/willingness to avoid), the long run marginal cost or the benefit transfer method;

- A long-term perspective is adopted, over a time horizon ranging from a minimum of 10 to a maximum of 30 years. Hence the need to forecasting the future inflows and outflows in the long run. In particular, this forecasting exercise includes the demand analysis, for which specific assumptions about the elasticity of quantity to prices should be made;

- The perspective of analysis is the society as a whole, but the identification of costs and benefits can also be done from the point of view of all the groups concerned (which must be estimated separately).

Given the above depicted common conceptual framework, national-specific traditions and practices of CBA still exist and show some differences in the practical application of the analysis. Also, each sector of intervention (transmission, environment, energy, etc.) has developed its own peculiarities and specific rules. The next sections presents the conceptual framework of the CBA (the “six steps” for project appraisal).

Standard CBA is ideally structured in six steps[8]. They are:

1. A presentation and discussion of the socio-economic context and the objectives
2. The clear identification of the project
3. The study of the feasibility of the project and of alternative options
4. The Financial Analysis
5. The Economic Analysis
6. The Analysis of Uncertainties and Risk Assessment

The core of a CBA lies in particular in the Financial and Economic analysis (steps 4 and 5). Financial effects are those corresponding to actual cash flows (investment costs, revenues from tariffs, etc), while economic ones are those affecting social welfare. The difference between the two lies in the fact that market prices, used in financial analysis, may not correspond to shadow prices, used in economic analysis to reflect the opportunity costs of resources, due to market distortion, fiscal effects or lack of a proper market. Disregarding such effects usually leads to sub-optimal welfare choices.

2.1.1 Socio-economic context and objectives

The broad question the investment appraisal should answer is "what are the next benefits that can be attained by the project in its socio-economic environment?". Thus, as a preliminary step, there is the need to understand the social, economic and institutional context in which the project will be implemented. To this end, it is necessary to define the physical and administrative boundaries of the area concerned by the project as well as all public and private entities that have a role in it. This exercise is instrumental for carrying out the analysis of all future values, especially for demand analysis.

[8] Although this presentation follows the structure of the EU Commission CBA Guide for major projects, the key concepts are those shared by the international literature on the subject.

The appropriate level of analysis and perspective is decided on a case by case basis. For utilities providing municipal services the local perspective is appropriate, while in order for the infrastructure to be a part of an integrated network, notwithstanding the regional scope of the individual intervention, a broader perspective can be more suitable. For instance, for Trans-European Network, such as Transmission or Energy infrastructures, a European or multi-national perspective is worth adopting[9]. Finally, in case of environmentally related issues, such as global warming, a global perspective is advisable.

A clear statement of the socio-economic objectives of the project is a precondition for the forecast and ex-post assessment of the project impact. They should be well defined and logically connected to the investment, but also consistent with the policy or program priorities, which have a broader scope than that of the investor. They may relate for example to the improvement of the output quality, better accessibility to service or increase in attractiveness[10].

Moreover all bodies, public or private, which are part of the project should be identified, along with their specific role and the mutual interrelationships of any kind: institutional, contractual, financial or otherwise.

The characterization of the stakeholders, which is needed if an analysis of the distribution of costs and/or benefits is requested, is even suitable for the identification and quantification of the different costs and benefits of the project (see 1.2.2).

2.1.2 Identification of the project

Once assessed, the objectives and the context in which the project will be implemented, the physical boundaries of the investment must be identified. In

[9] In the case of projects that are part of a network at a national or international level (where mutual dependencies are relevant aspects in assessing the economic consequences) particular attention should be paid. When projects belong to networks, their demand, and consequently their financial and economic performance, is highly influenced by issues of mutual dependency and accessibility: projects might compete with each other or be complementary. Also, in the case of cross-border projects, the country of the implementing body, bearing the costs of the realization, may be not necessarily the place where the beneficial effects of the project occur.

[10] On the contrary, CBA is not meant to analyze macroeconomic impacts of the given project; rather, macroeconomic data might be used as inputs of the analysis.

particular, the object of the CBA has to be a self-sufficient unit of analysis[11]. Sometimes a project can consist of several inter-related but relatively self-standing elements. Appraising such a project involves, firstly, the consideration of each component independently and, secondly, the assessment of possible combinations of components. In such a case, a simplified CBA for different options related to that component might be carried out in order to test their impact on the whole projects. The opposite occurs in the case of multi-staged projects, with individual but not functionally independent components implemented (and financed) in different steps (and possibly by different sponsors). The unit of analysis in this case should be the unit made of all the components.

Project identification also entails that indirect as well as network effects have to be adequately taken into account and the risk of double counting has to be avoided. Indirect effects are monetary impacts the project can have on secondary markets, affecting third parties not directly involved. In principle, market effects on secondary markets should not be included since they are already captured by shadow prices (if properly calculated – see 1.1.5)[12]. Network effects are present the whole time that a new realization belongs to an already existing network. These effects instead, should always be considered through an appropriate forecasting model able to capture possible diversion of flows generated into the network by the new infrastructure.

Connected to the problem of project identification is the issue of the identification of all the groups of individuals affected, directly or indirectly, by the interventions (see 1.2.1). The identification of the relevant stakeholders affected by the project is known in the literature as the 'standing' issue ("who has standing?"). As previously said, effects can be identified and calculated by considering separately those accruing to each relevant stakeholder, and, in the aggregation, compensations should be considered in order to avoid double counting.

[11] The EC CBA Guide provides the following example: "a hydroelectric power station, located in X and supposed to serve a new energy-intensive plant in COUNTRY: if the two works are mutually dependent for the assessment of costs and benefits, the analysis should be integrated".
[12] Both positive and negative externalities are instead non-market impacts belonging to the primary market, thus falling within the scope of the CBA analysis.

2.1.3 Study of the feasibility of the project and alternative options

Undertaking a project entails the simultaneous decision of not undertaking all other feasible options. Therefore, in order to assess the economic convenience of a project, a range of options should be considered for comparison. There are three different moments in this step:

- Option identification;
- Feasibility analysis;
- Option selection.

As for the first point, once the potential demand for the output of the proposed project has been analyzed, the next step consists of identifying the range of options that can ensure the achievement of the objectives. It is suggested to consider a Business As Usual scenario (BAU)[13] which will be used as reference from where to compare the outcomes of alternative options, which might range from a so called "do-minimum" scenario (the least cost project that ensures compliance) to the best option available. This will give the possibility to rank all the options according to their net benefit.

Feasibility analysis, instead, aims at identifying potential constraints and related solutions with respect to technical, economic, regulatory and managerial aspects. A distinction between binding constraints (e.g. lack of human capital, geographical features) and soft constraints (e.g. specific tariff regulations) may be stressed, because some of the latter can be removed by suitable policy reforms.

Finally, option selection is carried out with a simplified CBA analysis, which will guarantee the possibility of ranking different options and of performing a detailed CBA on the most promising solution. The calculation of both financial and economic performance indicators has to be made with the incremental net benefits technique,

[13] In case the BAU hypothesis leads to a catastrophic situation, a 'do minimum' is a more realistic reference case. In the few cases when the 'do minimum' leads to catastrophic or unrealistic scenarios (e.g. existing infrastructures at the end of their economic life), the 'do nothing' can be adjusted, e.g. considering the stop of the technical functionality of the existing infrastructures as the BAU scenario.

which considers the differences in net benefits between the various alternatives and the business as usual case.

2.1.4 Financial analysis

The financial analysis is the starting point of the core calculations of CBA. It allows identifying and calculating all the monetary inflows and outflows of an investment project and their future values over a given time horizon. Financial analysis is carried out in order to assess the project profitability (indicating the project convenience under a private investor point of view) and sustainability (financial feasibility condition for any typology of project).

The key principles for the financial analysis are the following:

- A cash flow method is adopted: only monetary values are relevant for the analysis. All other accounting variables, normally used in business accounting for fiscal or other purposes (e.g. depreciation, capital reserves) are not relevant for the analysis;
- An incremental approach is used, on the basis of the differences in the costs and benefits between the scenario with the project and the counterfactual scenario without the project (BAU scenario), considered in the option analysis.

Data required to perform a financial analysis relate to:

- **Investment costs**: they include the costs of all the fixed assets, start-up costs and replacement costs for short life equipment. According to the incremental approach, these costs should be considered net of possible avoided capital costs in the reference scenario. The latter costs are based on the assumption that, without the investment, there is a no longer a feasible situation so that it is in any case necessary to implement some other interventions at least in a way to guarantee a minimum service. This is the assumption of taking the ‘do minimum’ option as the reference scenario, e.g. in the electric sector a new substation is needed to satisfy the load increase in the absence of a new line. It is worth noting that avoided costs are included in the financial analysis only if affecting the project owner/proposer.

- **Operating costs:** they include all the incremental costs for operating the new service. They are calculated as the costs to run and maintain the new or the extension of an already existing infrastructure, net of the costs borne to run and maintain it before the intervention. Possible cost savings deriving from an upgrade intervention shall also be included.

- **Revenues:** they include incremental inflows accrued by the project owner. They may come from additional income from tariffs, due to an increase in volumes, in the level of tariffs, or both (in public services, usually the cost of the investment is passed from the investor to the end-users via an increase in tariffs). One should notice that when we evaluate a new energy transmission infrastructure from the point of view of a sectoral regulator the revenue stream is usually determined by the regulator himself in such a way as to allow the investor a fair return on invested capital. The estimate of revenues may not be an issue in this context. The project should be realized as long expected (social) costs are lower than expected (social) benefits).

- **Sources of funding**: they include equity capital of the private investor, capital from loans (in this case loan repayment and interests are a project outflow for the sustainability) and any additional financial resources such as grants. Again, source of founding could be endogenous if they are decided by the social planner (regulator).

Information about the above variables and future values are gathered from:

- The demand analysis[14], for what concerns the needed capacity and the expected revenues;

[14] Along the horizon time that has been set for the analysis.

- Technical feasibility, for what concerns the time horizon considered, the investment and O&M costs estimates;
- Balance sheets for the current reference values against which the incremental values should be gathered.

Forecasting modelling are often used to obtain future values.

Determination of investment costs, operating costs, revenues and sources of financing allows to assess the output of the financial analysis, which is measured by the following key indicators:

- **Financial Net Present Value – FNPV(C) - and the Financial Internal Rate of Return – FRR(C) - on investment**. They compare investment costs to net revenues and measure the extent to which the project net revenues are able to repay the investment, regardless of the sources or methods of financing. An even negative financial rate of return does not mean that the project is not in keeping with the expected objectives, but only that it is not viable in the financial market. For infrastructural investments return on investment is usually very low or even negative, while for the productive sector the FNPV(C) is usually positive.
- **Financial Net Present Value – FNPV(K) - and the Financial Internal Rate of Return - FRR(K) - on capital**. They compare equity provided by the investor to net revenues and measure the extent to which the project net revenues are able to repay the equity. Financial profitability on capital is expected to be significantly positive in case of purely private investments, slightly positive in case of regulated markets or subsidized projects, and negative in case of unprofitable projects. It allows understanding and calculating whether the investor can carry out the project with equity or loans gaining a reasonable return, or if some external incentive (in the form of public funding for example) should be envisaged.

- **Financial sustainability**. The project is financially sustainable when it does not incur the risk of running out of cash in the future. The crucial issue here is the timing of cash proceeds and payments. Project financial sustainability is measured by the cumulated net cash flow, which should be positive for all the considered years of the time horizon for the project to be feasible. The balance of inflows and outflows is assessed year by year and no discounting is required in this case.

2.1.5 Economic analysis

This analysis is carried out from the point of view of a benevolent social planner, which will thus take care of the interests of the whole society. The key concept is the use of accounting shadow prices, based on the social opportunity cost, instead of observed prices which may be distorted. Thus, the starting point of the economic analysis is the calculation of the financial rate of return of the investment (investment costs against net revenues), and then some adjustments are applied in order to correct market inefficiencies (reflected in market prices) when occurring. Sources of market inefficiencies are manifold:

- Non-efficient markets where operators can exercise their power: in this case the observed price also includes a mark-up over the marginal cost;

- Administered tariffs for utilities may fail to reflect the opportunity cost of inputs due to affordability and equity reasons;

- Some prices reflect fiscal requirements rather than opportunity cost (e.g. wages include social security payments, imports may include duties and other taxes);

- For some effects no market (and prices) are available (e.g. air pollution, time savings);

Three adjustments usually applied in the CBA approach. They are:

- From market to shadow prices;
- Fiscal corrections;
- Evaluation of non-market impacts.

After market prices adjustment and non-market impacts evaluation, costs and benefits occurring at different times must be discounted. The discount rate in the economic analysis of investment projects - the Social Discount Rate (SDR) - reflects the social view on how future benefits and costs should be valued against present ones. It may differ from the financial discount rate when the capital market is inefficient (for example when there is credit rationing, asymmetric information and myopia of savers and investors, etc.)[15].

After the choice of an appropriate social discount rate, it is possible to calculate the project's economic performance using the following indicators:

- **Economic Net Present Value (ENPV)**: the difference between the discounted total social benefits and costs;
- **Economic Internal Rate of Return (ERR)**: the rate that produces a zero value for the ENPV;
- **B/C ratio**, i.e. the ratio between discounted economic benefits and costs.

[15] The social discount rate is a core parameter in CBA. Among the different possible approaches, the new edition of the EC Guide to Cost Benefit Analysis of Investment Projects (2008) has taken the view that the Social Time Preference Rate (STPR) approach is the reference one. The key concepts here are the growth rate of per-capita income (or a related macroeconomic variable), the elasticity of marginal social welfare to this variable and a pure preference time rate. The standard formula is: SDR= $eg+p$, where SDR is the social discount rate, g is a growth rate of an appropriate macroeconomic variable (usually GDP because no long term estimates are available for private consumption), e is the elasticity of marginal social welfare to the variable, and p is a rate of pure time preference.

From market to shadow prices

When market prices do not reflect the opportunity cost of inputs and outputs, the usual approach is to convert them into accounting prices using appropriate conversion factors, to be applied to each of the inflow or outflow items of the financial analysis. Accurate conversions can be achieved by breaking the inflows and the outflows in the basic components, for which well-documented conversion factors can be found and/or calculated. In principle, such parameters should be made available by a planning office[16] and not calculated on a project-by-project basis, however this is not always the case. Thus, some rules on the calculation of project-specific conversion factors are the following:

- For **tradable goods** international prices are used[17]. If a project uses an imported input, or produces an output which replaces part of an imported commodity, the shadow price is the import cost plus insurance and freight (CIF). This is done to bring the commodity from the port of entry to the point of consumption, either by the project entity or the households. If a project uses as an input good which is exported, or produces a good which adds to exports, the shadow price is the free on board (FOB) export price. In other words, the economic price of a good diverted from export (to domestic market) for consumption or for use as an input involves the determination of the costs saved and the revenue foregone by not exporting it.

- For **non tradable goods** the following applies:

  - For minor input items a Standard Conversion Factor is used[18];

  - For major input items, such as labour force, ad hoc conversion

[16] See for example the Guide provided by the Italian Evaluation Units, 2003 (available at http://country.retenuvv.it/utilita/prod_rete/guida_sdf.php)
[17] This rule comes from the tradition of applied CBA to developing countries, with highly distorted national or local prices, for which while international ones are a good approximation of opportunity costs. Although price distortions in the context here considered may be less relevant, the rationale remains valid.
[18] The Standard conversion factor (SCF) is equal to SCF= (M+X)/((M+Tm) + (X-Tx)); where M are total imports, X are total imports, Tm are total import taxes and Tx are total expert taxes. Those values are easily gathered from national statistics.

factors can be calculated;

- For output, long term marginal costs or willingness-to-pay are used as shadow prices (see evaluation of non-market impacts below).

Depending on the hypotheses made on market conditions (in case of labour, for example, they can relate to a level of taxation, sectoral and regional productivity differentials, wage rigidity, sources and a certain degree of market distortions, level of employment, trade and migration costs), suitable shadow prices could exceed or be significantly lower (becoming even negative under some approaches) than market prices. For wages, it is common to use a conversion factor which is less than one19. The shadow wage is region-specific, because labour is less mobile than capital. It may often be determined as a weighted average of:

- The shadow wage for skilled workers previously employed in similar activities: it can be assumed to be equal or close to the market wage;
- The shadow wage for unskilled workers drawn to the project from unemployment: it can be assumed to be equal to or not less than the value of unemployment benefits;
- The shadow wage for unskilled workers drawn to the project from informational activities: it should be equal to the value of the output forgone in these activities.

Under severe unemployment conditions and very low public unemployment benefits, the shadow wage may be inversely correlated to the level of unemployment[20].

Fiscal corrections

Some items in the financial analysis are pure transfer from one group to another in the society, therefore they are not relevant in economic terms (e.g. taxes paid by the

[19] Empirical studies with application to different developing countries, provides estimations for conversion factors for labour, ranging 0.36 for working children for farms households in Nepal to 1.29 for self-employed rice-producing households in Côte d'Ivoire (see Del Bo, Fiorio and Florio, 2009).

[20] An easy formula for calculation of the shadow wage (SW) under severe unemployment is SW = COUNTRY(1-u)(1-t) where COUNTRY is the market wage, u is the regional unemployment rate, t is the rate of social security payments and relevant taxes. The conversion factor here is (1-u)(1-t).

private investor). Some rules for fiscal corrections are the following:

- All prices for input and output should be considered net of VAT and other indirect taxes;
- Prices should be considered gross of direct taxes;
- Subsidies and other transfers granted by a public entity should not excluded from benefits.

In some cases fiscal corrections are made through the calculation of an appropriate shadow price (this justifies most of the conversion factor with a value less than 1), as for example in wages. When they are individual items in the financial analysis, e.g. taxes paid on profits, they are simply dropped for the economic analysis.

Evaluation of non-market impacts

Some effects the project generates on users (e.g. better health conditions, time savings, prevention of fatalities, etc.) do not have a market and therefore no price is observed for them. Appropriate conversion factors applied to the financial values of the revenues already capture the most relevant non-market benefits a project may generate. However, if conversion factors have not been estimated for outputs, or the project is non-revenue generating, alternative approaches - in part depending on the nature of the effect considered - can be used to evaluate non-market benefits. Willingness to pay is the most used approach for measuring such effects. In some other cases, long run marginal costs may also be used. The use of willingness-to-pay or long run marginal costs as shadow prices is mutually exclusive to the application of conversion factors to the financial revenues of the project.

When non-market effects do not occur on the users of the infrastructure, but they spill over from the project affecting third parties, they are called externalities. Environmental effects are a typical externality which is relevant in the context of CBA[21]. Due to their nature, external effects are not captured by the use of shadow prices for outputs and they need to be evaluated separately through willingness-to-

[21] See Pearce, Atkinson and Mourato (2006) for a review of recent literature.

pay or willingness-to-accept estimates. Three main methodologies are identified for the evaluation of environmental externalities:

- Revealed Preference Methods;
- Stated Preference Methods;
- Benefit Transfer Method.

Revealed preference methods stem from the observation of actual behaviours and decisions. The idea underpinning those methods is that market prices of observable goods or services may include the value of some environmental characteristics, for example the cost of a building with a nice view over a natural landscape. Specific methods relate to the hedonic pricing method, travel cost method, averting or defensive behaviour method, cost of illness method.

Stated preference methods are survey-based methods which elicit people's intended future behaviour in the markets. Contingent valuation and choice modeling are specific techniques in order to catch the willingness to pay of environmental goods.

It is however also possible to take advantage of the substantial literature on estimation of values of non-market goods, with the 'benefit transfer approach'[22], which uses as benchmark values estimations done elsewhere and adapted with appropriate transfer functions[23].

Finally, for some specific effects, studies and guidelines provide reference values to be used in a given context.

2.1.6 Risk Assessment

The final step of the appraisal is risk assessment. Risk assessment is basically the determination of the value of risk related to any variable of the project. The main aim

[22] According to this approach, reference is made to unit values of non-market goods estimated in other studies for similar projects, and they are used, with some adjustments if necessary, to value benefits or costs. See Atkinson (2006).

[23] Some databases have been set up to facilitate benefit transfer for environmental goods, see for example http://country.evri.ca/ or http://country.gevad.minetech.metal.ntua.gr/.

of this step is to s thus tudy the probability that the project will achieve a satisfactory performance and to highlight the critical variables necessary for that. In practice, it intends to test the robustness of the forecasting exercise, by measuring the likelihood and magnitude of expected variations from the base values. It allows both the investors and the regulatory agency to assess ex-ante the relative risks related to the project performance, including, if relevant, the risk of failure. The recommended steps for assessing the project risks are:

- Sensitivity analysis;
- Probability distributions for critical variables;
- Risk analysis;
- Assessment of acceptable levels of risk;
- Risk prevention.

The first step is sensitivity analysis. This step allows the determination of the "critical" variables or parameters of the model. Such variables are those whose variations, positive or negative, have the greatest impact on the project's performance indicator. In standard CBA terms, the variables defined as critical are the ones whose 1% variation results in more than 1% variation of the analyzed indicator. Generally, the analysis is carried out by varying one element at a time and determining the effect of that change on the standard indicators, namely IRR or NPV. A more complex form of sensitivity analysis is scenario analysis, in which it is possible to study the combined impact of determined sets of critical values. In particular, it is possible to combine "optimistic" and "pessimistic" values of a group of variables to build different scenarios, which might hold under certain hypotheses.

The second step is probability distributions for critical variables. Probability distribution is needed due to the fact that from the sensitivity analysis we just know what a percentage change in the critical variables would bring about, but we do not know the likelihood of this event. That is why, for all critical variables there is the need to compute their probability distribution.

The third step is risk analysis. Having computed the probability distribution of critical variables, it is possible to proceed with the calculation of the probability distribution of the IRR or NPV of the project.

The fourth step, namely assessment of acceptable levels of risk, allows for the selection of projects not only on the basis of the best estimate, but also based on the risk associated with it, simply by weighting the performance with the risk. To this respect, the Guide calls for a risk neutral approach as the public sector is able to pool the risk on a large number of projects.

The final step of risk assessment is the prevention of all possible risks. Risk prevention, as the Guidelines state, is basically the application of standard procedures and best practices aimed at reducing all the identified risks.

2.2 Adapting the CBA framework to the analysis of energy network development projects

In this section we will identify the specific features of electricity and gas transmission investments in the European context and discuss the implications for the assessment of their costs and benefits.

The institutional framework relevant to our analysis differs from the one in which CBA is typically performed. In the European countries the energy Regulators' mandate is typically narrower than that of the social planner implied in the standard CBA assessment. The Regulator's objective function is typically limited to maximizing the total surplus created in the industry. In addition the split of surplus generated in the industry between consumers and suppliers is highly relevant in the Regulator's agenda. Much of the Regulator's actions relate to preventing the exercise of market power within the industry, not only because of its adverse effects in terms of total surplus generated in the industry but, and above all, because of its welfare distribution implication. Environmental sustainability objectives impact on the Regulator's decisions but are not set by the Regulator; in a sense from the Regulator's point of view they can be interpreted more as constraints than as objectives.

The Regulator's objectives, though, do not typically extend beyond the industry that they regulate. Other institutions and policies address issues such as growth, inequality, employment etc.

These features result in three broad methodological implications. First, we refer to a welfare function whose scope is limited to the gas or the electricity industry. This means, for example, that our analysis will not assess the impact of the energy transmission infrastructure upgrades on the surplus created in the wire and pillar markets. The prices of the cables and of the pillars will enter our assessment as part of the investment cost. Second, we will take the actual investment costs and the current prices for the outputs to represent the correct economic values,. A standard CBA would instead assess the opportunity to replace those prices with figures reflecting the "real" social value of the resources, in case the two values were deemed to depart because of some market or other institutional imperfections. Finally, financial issues are highly relevant in the standard CBA framework, as CBA is often used to assess projects for the purpose of allocating support funds. In this context it is important to identify net-positive value projects that would not be viable without financial support. In the setting we are considering, though, financing issues are not any different from those involved in usual market investments. In particular, in a merchant framework (see chapter 3), in which private investors take the investment risk, public institutions are not involved in the financial viability assessment of the project. In a central planning framework, investment costs are passed on to the electricity and gas consumers via the tariff; therefore, once the desirability of the investment is ascertained based on the comparison between the benefits and the costs of the investments, any financial issues are addressed in the tariff-setting process.

3 Economic assessment of cost and benefits of transmission infrastructures

In this Chapter we address three broad methodological issues involved in the assessment of the net value of energy network upgrades common to electricity and gas investments.

In section 3.1, we discuss the role of the cost-benefit assessment under alternative institutional arrangements governing the investment decisions. In particular we will compare two extreme settings: the merchant setting and the central planning setting. We will argue that the European framework, as shaped by the single energy market Directives, although largely based on central-planning, contains elements of both approaches. We present the discussion on these issues mostly with reference to gas investments, as we expect that in the gas industry the role of central-planning and of merchant investment will be more symmetric than in the electricity industry. Therefore the coexistence of elements of the two approaches will raise more complex issues.

In section 3.2, we discuss the welfare function relevant for the assessment of the net value of network investments. In particular we address ways of the investments' benefits in the allocation (or reallocation) of the economic surplus generated in the industry between consumers and suppliers, to include in the assessment. This analysis is further developed in Chapter 7, where we address issues related to the surplus allocation between countries. We cast this section in terms of electricity transmission investments, as the policy debate on this matter is more developed in the electricity industry. The same concepts, though, can be applied to the gas industry.

In section 3.3, we turn to the relationship between the physical network infrastructure whose investment is being contemplated and the resulting incremental transmission capacity.

3.1 The role of the cost-benefit assessment under alternative institutional arrangements governing the investment decisions

The way the impact on social welfare of electricity and gas network upgrades is assessed depends on the institutional setting governing the development of transmission networks. The more the investment process is market driven, the less there is room for a central evaluation and control of network upgrades.

In this section we compare two extreme settings: the merchant setting and the central planning setting. The European framework contains elements of both approaches. Central planning appears as the default model, but merchant infrastructures are also allowed. In addition, in the gas sector the SO and the Regulator can require users of the incremental transmission capacity to commit to buying long-term rights to use the capacity resulting from the investment. That amounts to introducing an element of the merchant model. Namely, (part of) the risk related to the uncertain value of the new infrastructure is not allocated to end-customers.[24]

Our reading of the European institutional framework suggests an evolution towards a hybrid system to govern network developments, in which system operators will have the delicate role of coordinating their planning activity with the developments of the market, in terms of demand, supply, adequacy of the system and merchant investments in gas infrastructure. Member States will also enjoy wide discretion as to the allocation of the risks of new investments. In this respect, the basic framework set up in the Directive is the traditional one, placing all the risks on final customers, who

[24] In the natural gas case, for example, Directive 73/09 grants central-planner prerogatives to the SO (under the control of the Regulator). In this respect Art 14.4 is unambiguous: *Each independent system operator shall be responsible for […] operating, maintaining and developing the transmission system, as well as for ensuring the long-term ability of the system to meet reasonable demand through investment planning.* On the same line is basically the Regulation 994/10 where it introduces mandatory infrastructural standards on each SO's network and where it obliges them to set up plans to tackle (possible) disruptions. On the other hand, the TPA exemption regime for new gas infrastructures is maintained (Art. 36 of Directive 73/09) so that, under relatively mild conditions, merchant investments are allowed. Finally, within the central planning approach, Art. 22.4 of the Directive allows Regulators, when consulting the then year network development plans, to require "*Persons or undertakings claiming to be potential system users* " to "*substantiate such claims*". Despite its vagueness, that provision is compatible with mechanisms placing the risk of the investment in additional transmission capacity on the parties stating an interest in that capacity. Perhaps the (even weaker) reference to market testing investments enhancing security of supply, in the Regulation 994/10, could be interpreted along the same line.

bear the cost of all the investments selected by the SO and approved by the Regulator, irrespectively of their actual use and usefulness (in the US regulatory jargon). Nevertheless the institutional framework appears to be compatible with mechanisms placing (at least part of) the investment risk on the parties willing to acquire long term rights on the transmission capacity resulting from the investment.

We have already seen attempts to test the new institutional framework. Within the South Gas Regional Initiative, for example, Spain and France performed an open season to test whether the market was interested in increasing the interconnection capacity between the two countries, also with respect to reverse flows. The open season resulted in an overall subscribed capacity of 7.5 Bcm, of which 5.5 in both directions, representing 15% of the French consumption or 18% of the 2009 Spanish consumption. An interesting feature of this procedure was a condition on the minimum share of the risk allocated to market investors. The French and the Spanish regulators decided that the investment would take place only if the commitments to purchase the incremental capacity collected in the open season guaranteed revenues sufficient to cover at least 70% of the investment costs.

In discussing the impact of the institutional setting on the assessment of network upgrades we focus on gas investments, as we expect that in the gas industry the role of central-planning and of merchant investment will be more symmetric than in the electricity industry. Therefore the coexistence of elements of the two approaches will raise more complex issues. On the one hand, some long-haul transmission infrastructures are idiosyncratic to investments in gas production. For those investment the merchant regime appears to be the most suitable, as investors need to control access to the transmission capacity to reap the benefits of their investment in production over the relevant timeframe. On the other hand, the European Commission and some European regulators regularly highlight inefficiencies in the current capacity allocation and capacity development mechanisms, advocating for a wider involvement of public authorities in the network expansion decisions. Security of supply issues as well as market segmentation concerns provide an additional motivation in favour of centralized planning of the gas network developments.

In electricity, instead, the meshed part of the transmission network is much larger than the portion dedicated to one generator only. We are aware though, that the situation could change, as transmission investment upgrades are required to connect renewable generators at remote locations.

The merchant framework. In the merchant framework market investors develop and own network infrastructures. The key feature of the merchant model is that investment risks are borne by the investors. In particular investors bear the risk that the demand for the services of the infrastructure turns out to be lower than expected at the time of the investment. Similarly, the investors appropriate any rents that might be generated by the infrastructure.

Provisions improving coordination among the independent decision-makers can be implemented even in a merchant framework. For example, a party willing to build a new pipeline can be required to run an "open season" to test whether:

- Other parties are willing to develop further capacity on the same route, which could be efficiently done by building (only) a larger pipeline; or

- Other parties are willing to permanently relinquish existing transmission capacity on the same route, which would avoid needless duplication of the investments.

However, in this framework the role for an assessment by the SO and the Regulator of the value of the transmission upgrades is limited as the selection of the network upgrades remains basically decentralized.

As we will discuss in Chapters 5 and 6 public intervention may still have a role in a merchant framework to address externality and security of supply issues, provided market-based mechanisms in order to respectively internalize the externalities and ensure capacity adequacy are not in place.

Public intervention aiming at improving competition appears instead to be at odds with a merchant model. Consider a case where, within the framework of the merchant model public authorities decide to increase interconnection capacity through a "regulated" investment, after having verified that market investors are not ready to build that capacity on a merchant basis. That decision must be based on either:

- The assumption that the Planner has better information than the market on the value of the transmission capacity. For example the Planner might believe that the market is not predicting the future supply/demand balance correctly in the involved countries or, more generally, that the market is underestimating the future spot price differentials.

- The assumption that some market imperfections discourage investors, despite the fact that they correctly assess the value of the network upgrade. For example, it is typically difficult to induce final customers to commit to long-term supply contracts and this might prevent would-be investors to hedge their position in a time horizon consistent with the network investment life. Or there may be imperfections in the long-term transmission rights allocation mechanisms. In fact, for a merchant model to be effective we need a system of long-term transmission rights in place, covering the entire network capacity. Moreover, investors must be certain that by building a certain infrastructure they will be allocated the transmission rights resulting from their investment, for the entire economic life of the infrastructure. Finally, the endowment of transmission rights corresponding to the investment must not change in the future, for example as a consequence of additional investments by other parties.

- The assumption that the market would not adequately take into account some externalities. This is often the case, for example, for security of supply concerns or for environmental externalities. Sometimes the need to increase the competitive pressure by widening the geographic dimension of European (still fragmented) gas markets is brought forward as a justification for regulated infrastructural investments as well.

All the arguments stated which support the “regulated” investments, when merchant investments are allowed, should be carefully looked at.

The first argument is based on the presumed superiority of the public authority over the market players in predicting the gas market dynamics. Such a view cannot be easily reconciled with the (usual) motivations underpinning the liberalization of the industry.

The second and third arguments are based on some form of “failure”, preventing the merchant model from delivering the efficient outcome. In this respect, one may question, on the one hand, whether those failures could be removed (or their effects mitigated) in order to increase effectiveness of the merchant approach. For example, distortions of the market investors decision might be caused by elements of the regulatory framework that:

- Lead the underwriters on long term transmission rights allocated by the public authority in order to pay a price different from the actual incremental cost of making those rights available;
- Expose underwriters to the risk that the cost for them to use that capacity will change in time because, for example, the transmission tariffs reflect some averaging of the total network costs;
- Do not guarantee underwriters full flexibility in the use (on non-use) of the transmission capacity they committed to purchase.

The possibility that the merchant approach is in some cases unable to attract market investments in positive net-valued projects cannot be ruled out. Nevertheless, in this context, a decision by the public authority to carry-out an investment not appealing to market investors in the regulatory regime is an anomaly.

The central planning framework. In a central planning framework an institution, which we refer to for simplicity as the Planner[25], is responsible for network investment decisions and acts on behalf of the customers. The distinguishing feature of this approach is that the risks of the investment in network infrastructures are placed on end-customers, who are committed by the Regulator to covering the cost of the network independently of its use and of its value in the future. This is typically obtained by including the investment cost in the regulated rate-base of a transmission company. Transmission tariffs are then adjusted on a regular basis in order to grant a fair rate of return on the transmission company's invested capital. Compared to the merchant setting, public institutions play a prominent role in the planning framework; the Planner decides the investments and commits end users to paying for them. In the rest of the report our analysis of the methodology to assess the costs and benefits of transmission upgrades is carried out under the assumption that Central Planning is the default model governing network expansion. We recognize though that the European framework is evolving towards a hybrid model, where merchant investments are also allowed and must be kept into account by the Planner.

3.2 The perspective for benefit calculation

The standard notion of economic welfare –the sum of consumer surplus and firm's profit – is the obvious starting point to assess the social value of transmission upgrades.

A first dimension of the perspective for benefit calculation is geographic. Transmission investments often impact consumers and generators located in different countries. Therefore an input to the analysis is the geographic scope of the benefit (and cost) assessment. Traditionally costs and benefits of network upgrades have been calculated with reference to a country; in the future, provided investment decisions are taken (and the corresponding cost covered) on a multi-national or

[25] Authority over the decision to invest in network upgrades in the European countries is shared among the SO, the Regulator and the Government. We do not investigate here the properties of each country's institutional arrangements, nor the incentive-issues resulting from the delegation of powers. We assume here that a benevolent Planner takes investment decisions with the objective of maximizing the social welfare.

regional basis, a wider geographic perspective for benefit and cost calculation could become relevant. We address the cross-border issues in greater detail in Chapter 7.

Furthermore, the standard notion of welfare is neutral to mere surplus transfers across stakeholders. Therefore the competent authorities might consider that an assessment based on that standard welfare notion does not account adequately for the beneficial effect in terms of the promotion of competition.

In this paragraph we review the standard notions of consumer surplus and total welfare; we then move on to discuss a "modified welfare" notion developed by the California system operator (CAISO) specifically in order to account for the effects of network investments on the surplus' distribution between electricity generators and consumers.

3.2.1 Consumer surplus and total (net) surplus

In simplified terms, the benefit from an increase in interconnection capacity between, say, country A and country B resulting in a price reduction in A and a price increase in B would be equal, from a consumer surplus perspective, to the sum of the following components:

- A positive component: the price reduction in A caused by the increasing interconnection capacity multiplied by withdrawals in A;
- A negative component: the price increase in B caused by the increased interconnection capacity, multiplied by withdrawals in B;
- A component with an undetermined sign, that is the variation in SO's congestion revenues (under the hypothesis that those revenues will be transferred to customers). The sign of this component is undetermined since transmission projects substantially increasing transfer capacity between areas may tend to reduce the congestion rents, while projects with small (but still positive) impact on transfer capacity may tend to increase congestion rents;

- A component with an ex-ante undetermined sign: the reductions in the cost paid by SO for ancillary services (reserve capacity, intra-zonal congestions). The sign of this component is undetermined since it is possible that a transmission project which contributes to increasing ATC between areas may create additional ancillary service costs, for example to guarantee firmness of the additional capacity or to solve newly created internal congestions.

The total surplus perspective calculates the effect of the transmission expansion by summing up consumer surplus (as described above) and generators' profits. The total welfare notion is neutral to welfare transfers between generators and consumers and it will not capture the effects of the network upgrade in terms of increased competition, even though the objective of increasing competition is commonly regarded as an important reason for network upgrades. Again, it is possible that the new transmission expansion affects subgroups of both consumers and generators in a different way, thus the final assessment of the investment can differ if one takes a national instead of an international perspective. In the context of the previous example, total net surplus would be obtained by adding the following components to the consumer surplus:

- A positive component: the profit increase for generators in B, as they will benefit from increased withdrawal in A and higher prices in B;

- A negative component: the profit decrease for generators in A, caused both by the lower amount of electricity that they will be able to sell and the price reduction in A.

Prices used in the calculation of consumers' and generators' surplus are market prices that reflect both costs and the strategic behaviour of generators. In markets where generators' strategic behaviour is believed to be insignificant, prices could be estimated as equal to the variable costs of the generating units that are marginal in providing power in each price-area.

3.2.2 Modified total surplus

The *modified total surplus* is a notion developed by the CAISO to account for the welfare redistribution effects of network upgrades. The drawbacks of the standard welfare concept that the modified notion is meant to overcome can be illustrated through a simple example.

Consider again the simplified setting of an increase of interconnection capacity between country A and country B. In this case, though, assume that generators located in country A enjoy significant market power, so that electricity prices in A, before the network upgrade, are materially above the corresponding marginal cost. Prices in B are instead assumed to equal marginal cost. To make the example simple, let us also assume that marginal cost in A is lower than marginal cost in B and that demand is inelastic in both markets.

Finally, in order to make our point we consider the somehow extreme case in which, after interconnection capacity is increased, imports from B to A do not change. In other terms we assume that generators in A find it convenient to reduce the price slightly below the cost of the marginal generator in B in order to prevent additional imports.

According to the total welfare metric discussed in the previous section, in our example the investment does not produce any welfare gain. As a result of the greater competitive pressure exercised by generators located in B, because of the increased interconnection capacity, generators in A reduce their prices. Customers in A are better off, since they pay less; generators in A are worse off, since they sell the same amount of power at lower prices; generation costs do not change, since productions in A and B do not change. Since the total welfare notion is neutral to welfare transfers between generators and consumers, it will not capture the effects of the network upgrade in terms of increased competition, even though the objective of increasing competition is commonly regarded as an important reason for network upgrades.

The modified total surplus assesses the effect of the transmission expansion not on the actual generators' profits but on the profits that generators would collect under perfectly competitive market conditions. The Modified Total Surplus due to transmission expansion is then calculated as the sum of:

- The net increase in consumer surplus as defined above;
- The net increase in generators' *competitive* revenues calculated as the product of the system marginal cost in the relevant geographic area and the corresponding injections; and
- The net reduction in total cost born by generators.

In our example, the modified surplus metric would signal that the network upgrade results in a welfare gain. The consumer's surplus increase would be accounted for in the modified surplus calculation, but the (matching) generator's profit decrease would not, because the interconnection capacity increase in the B to A direction does not change the profits that generators in A would make under perfectly competitive assumption.

3.2.3 Assessment

The total surplus perspective is solidly grounded on the standard economic theory and, by treating all the stakeholders equally, it appears to be more consistent with the neutral position of the SO in the industry.

Although promoting competition is a crucial objective of network development, a finding that the main justification for a network upgrade is a mitigating market power, without any significant cost-reducing effects, would lead to the investigation of the opportunity to implement alternative and possibly less expensive market power mitigation solutions.

Those arguments are clearly less compelling in the gas industry in which, on the one hand the inclusion of producers' profits in the welfare function is not obvious.

On the other hand, alternative measures to mitigate the producers' market power might not be available.

We stress however, that the ultimate decision on the relevant perspective for the assessment of the value of transmission investments, in terms of both geographical boundaries and surplus distribution effects, should rest with the Regulator or, more generally, with the Government.

In any case, for a more informative assessment, the SO should separately calculate the gains and losses not only for the different stakeholders, namely:

- Consumers in different market areas (at least on a national basis)[26] [27];
- Generators in different market areas (at least on a national basis);
- System operator (e.g. in terms of lower ancillary service costs).

3.3 Transmission rights and network capacity

Transmission is an input for electricity and for gas supply. Therefore the value of a transmission upgrade, in broad terms, is the net-surplus of the additional transactions that can be carried out after the upgrade. For both gas and electricity alternative sets of transactions can be supported by the transmission network. Therefore assessing the value of a network upgrade requires identifying the set of additional transactions with the highest net-surplus that can be supported as a result of the upgrade.

In Chapters 4 and 5 we develop methodologies for the SO to assess the net-surplus of the incremental transactions made possible by the upgrade. Those methodologies differ in order to reflect the technical feature of the gas and of the electricity supply. For electricity, the proposed methodology reflects the variability of the value of electricity in very short timeframes. The assessment is then carried out with

[26] In the CAISO case, it is suggested estimating the transmission investment benefits for the entire Western Electric Coordinating Council (WECC) that includes several western US states and Canadian provinces. However, the methodology also makes possible the benefit evaluation for California only.

[27] CAISO and London Economics, "A Proposed Methodology for Evaluating the Economic Benefits of Transmission Expansion in a Restructured Wholesale Electricity Market," February 2003, (CAISO & LE), p. 12; CAISO, "Transmission Economic Assessment Methodology (TEAM)," June 2004 (TEAM), p. 15

reference to the market mechanism that determines the most efficient use of the available network resources on a short timeframe, typically hour-by hour. In that setting transmission rights are allocated “implicitly”, within the process that determines the minimum cost set of generators that will produce. For the gas industry, instead, the proposed methodology reflects the fact that longer-term transmission rights are allocated “explicitly”. Market participants will then schedule injections and withdrawals, within the limits of the owned transmission rights. Those injections and withdrawals will result in physical flows across the network.

The impossibility to establish a link between transmission rights and physical flows is extreme for electricity; as a consequence the entry-exit design for short-term transmission rights has been implemented for a long time in several electricity markets.

In the gas industry the variability of the gas flows across the network can be expected to increase as the market develops and more short term trading takes place. Physical gas flows on the network will progressively depart from those implied by the commercial transactions. This is reflected also in the industry regulation: Regulation 715/2009 has mandated an entry/exit charging system for the use of the European gas transmission networks. Therefore the relationship between an infrastructure upgrade and the incremental set of transmission rights that can be allocated to the market as a result of that upgrade is expected to be more complex in the future than in the past.

In the rest of this section, therefore, we present a brief analysis of the relationship between transmission rights, physical flows and network upgrades with reference to the gas sector.

By *transmission rights* we mean the rights that market participants purchasing access to the transmission system are entitled to. In the gas industry transmission rights have been traditionally defined as point-to-point, i.e. as the right to inject a certain quantity of gas at a node and to withdraw it, at the same time, at a certain other node.

An alternative design of the transmission right – the entry/exit model – defines independent injection and withdrawal rights. A market participant willing to transport gas between two nodes in an entry/exit system needs to buy two matching rights: one "entry" right at the injection point and one "exit" right at the withdrawal point.

The following example illustrates the relationship between transmission rights and physical flows. For simplicity purposes we discuss the example in terms of point-to-point transmission rights. We will later discuss the implication of the entry/exit design.

In our example one market participant has purchased 60 Mcm/day transmission rights from point A to point C, and one market participant has purchased 25 Mcm/day rights from point D to point B. Assume, as it is typically the case, that those rights are defined as "options", i.e. the right-owner has the possibility to not use her transmission capacity. This means that each subset of the allocated transmission rights must be feasible, irrespective of whether the remaining rights are exercised or not.

In our example the first market participant can select any level of simultaneous injections (in A) and withdrawals (in C) in the range 0-60 Mcm/day. The second market participant can notify any level of simultaneous injections (in D) and withdrawals (in B) in the range 0-25 Mcm/day. We assume for the purpose of simplicity that all the security constrained is summarized in the pipeline capacity constraints. Let us first assume that the capacity of Pipeline 1 (for simplicity in both directions) is 65 Mcm/day. In this case, the set of transmission rights that were allocated to the market passes the "simultaneous feasibility" test: the gas flows that would result from any possible level of utilization of those rights can be hosted by the network without violating any of security constraints.

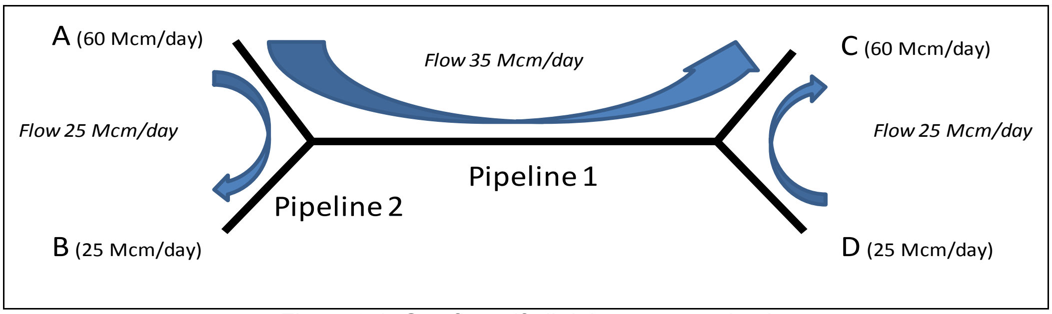

Figure 3.1: Gas flows if all rights are exercised

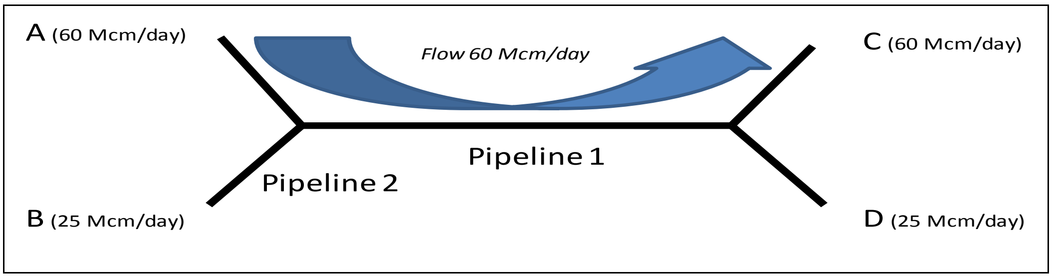

Figure 3.2: Gas flows if only A to C rights are exercised

The flows resulting when both market participants fully exercise their transmission rights are shown in Figure 1. Those obtained when the D-to-B rights are not exercised, while the A-to-C rights are fully exercised are shown in Figure 2.

Assume now that that the capacity of Pipeline 1 is 50 Mcm/day. In this case the set of transmission rights that we are considering does not pass the simultaneous feasibility test. In particular if the first market participant fully exercises the A-to-C rights, while the second market participant uses less than 10 Mcm/day, the resulting flows will violate the constraint on Pipeline 1.

Our simple example highlights some implications of the gas-transmission technology on the arrangements implemented to allocate the rights of using the system and on the methodology to assess the value of network upgrades. First, the set of transmission rights allocated to the market should be feasible. If this is not the case, and if not feasible flows result from the exercise of the existing transmission rights, then the SO has to bear re-dispatch costs in order to guarantee network security.

Second, some aspects of the design of the transmission rights have little or no impact. Consider a set of entry/exit transmission rights equivalent to the point-to-point set assumed in our example: Entry in A: 60 Mcm/day, Entry in D: 25 Mcm/day, Exit in C: 60 Mcm/day. Exit in B: 25 Mcm/day. That set of transmission rights is identical to the point-to-point alternative from the point of view of the SO. The different designs imply no differences on:

- Network operations, since the set of (aggregate) injections and withdrawals that could possibly result from the exercise of either set of rights is the same;

- Network planning, as the economic value of the alternative sets of transmission rights is identical.

Alternative designs of the transmission rights have an impact on the SO activities only to the extent that they result in different sets of flows that could result from their exercise. Transmission rights can for example be designed as obligations, i.e. the owner has the obligation to notify injections and withdrawals consistent with the full exercise of her rights. In our example, let us assume that the B-to-D rights are designed as obligations. In that case the SO knows with certainty 25 Mcm/day simultaneous injections in D and withdrawals in B will occur. As a consequence the SO can issue up to 85 Mcm/day A-to-C (option-type) rights, if the capacity of Pipeline 1 is 50 Mcm/day, as the SO can rely on the 25 Mcm/day counter-flow created by the injections in D and the withdrawals in B.

Third, a physical infrastructure can support alternative sets of transmission rights. In our example, assuming again that all the transmission rights are designed as point-to-point options, each of the sets of rights satisfying the following conditions is feasible:

- A-to-C + A-to-D + B-to-C + B-to-D < Pipeline 1 limit in the West-to-East direction;
- C-to-A + D-to-A + C-to-B + D-to-B < Pipeline 1 limit in the East-to-West direction.

where we indicate with COUNTRY-to-Z the amount of transmission rights from point COUNTRY to point Z allocated.

For each additional network constraint the range of the feasible sets of transmission rights shrinks. For example, if Pipeline 2 has a capacity of 25 Mcm/day in both directions, the following additional constraints need to be satisfied by any feasible set of transmission rights:

- B-to-A + B-to-C + B-to-D < 25

- A-to-B + C-to-B + D-to-B < 25

Having illustrated the relationship between transmission rights, physical flows and network upgrades, we now turn the methodology to assess the value of network upgrades in the electricity and in the gas sectors.

Investments increasing "flexibility"

Some transmission network investments are identified as aiming at increasing the system's flexibility. In line with the previous discussion we interpret an increase in "flexibility" as an expansion of the set of possible combinations of transmission rights that can be supported by the physical network infrastructure. In that interpretation, an increase in flexibility does not create additional issues, compared to a straightforward increase in transmission capacity. As we discuss in Chapter 4, in a central planning approach to transmission development, the value of a wider set of transportation options needs to be assessed based on the probability of alternative demand and supply scenarios – each one implying a different demand for transmission services. In the alternative approach, relying on the market demand for long-term transmission services in order to determine the value of network upgrades, the value of flexibility can be "market-tested" by enriching with flexibility elements the long-term transmission rights offered to the market.

4 The evaluation of electricity transmission investments

In this chapter we present a methodology for assessing the impact on total welfare of electricity transmission upgrades under a central planning framework. We organize the presentation in five sections. In the first section we present the core tool to simultaneously assess most of the benefits and costs of network upgrades: the security constrained optimal dispatch model. In the second and third sections we discuss the impact of the transmission upgrades on market power in generation and on transmission reliability, which we propose of assessing outside the core model. In the fourth section we address uncertainty and scenario selection. Finally, in the fifth section we discuss the impact of external effects.

While discussing the proposed methodology we will make reference to cases in which the techniques we describe have been implemented.

4.1 Security constrained optimal dispatching model

A significant part of the benefit of a transmission upgrade results from its impact on a generator dispatch, and as a consequence, on generation cost. Further, different types of network expansion benefits are typically interdependent. For instance, a network upgrade may impact on cross-border interconnection capacity at the same time, domestic transmission capacity and the deliverability of renewable power.

The interdependence of many benefit types can be addressed by calculating all the benefits in the integrated manner. That can be achieved by explicitly modelling the optimal generation dispatch in the market. Such modelling can be done applying optimization techniques to the constrained optimal dispatch problem. In such a problem power injections of generators are chosen to minimize the total cost in order to meet the demand, while satisfying the security constraints on the resulting power flows.

Security Constrained Optimal Dispatch (SCOD) is “the operation of generation facilities to produce energy at the lowest cost to reliably serve consumers, recognizing any operational limits of generation and transmission facilities."[28] This definition evokes the way utilities dispatch their own and purchase resources to meet the electricity load. The same modelling logic, though, can be used to forecast the market outcome "with and without" a proposed network upgrade, in order to assess the benefits of the investment.

Economic theory provides the foundations for using a centralised SCOD model to forecast the market outcome. The "welfare theorems" establish the equivalence between the competitive market outcome and the outcome that would result if a benevolent social welfare maximizing planner controlled the entire generation portfolio.

This equivalence is directly reflected in the design of most of the US wholesale spot markets (for example, the PJM, NYISO, NEPOOL markets), where the market clearing algorithm is subject to network-security and generation-feasibility constraints identical to those found in the traditional optimal dispatch models. In other terms the market clearing algorithm is nothing different from a SCOD algorithm, using as inputs the generators' offers instead of their cost information.

Since the generators offer function, under perfect competition assumptions, it is equal to the incremental cost function, the market solution coincides with the optimal dispatch solution, since the optimisation problems from which they result are identical.

In the European context, spot markets are cleared without taking network security constraints into account and the injection/withdrawal schedules are not defined as a part of the market clearing process. Each market participant autonomously decides and notifies the SO the injection/withdrawal schedules that she intends to perform to honour the commitments made on the market. In the case that these programmes, on an aggregated level, are incompatible with the system security, the SO purchases ancillary services to solve the issues.

[28] Harvey S., Hogan COUNTRY., Pope S. (1997) "Transmission Capacity Reservations and Transmission Congestion Contracts". Pp. 41-44. William Hogan (2000) "Financial Transmission Right Formulations".

In this context, the equivalence between the final market outcome and the results of a SCOD model still holds. The idea is that without any major market imperfections, market participants – including the SO in its role of buyer of ancillary services - have an interest in exploiting all the available gains of the trade. As a result of the transactions in all the markets – including the ancillary service market –the cost minimising (security constrained allocation of production among the generators would result. But this allocation is the same as the one that would result from the SCOD model.

Therefore, even with a "European-style" wholesale market design, the SCOD can be a good predictor of the market outcome. In this case though, the SCODM will not directly predict the distribution of the surplus across the market participants, as it would for a "US-style" spot market design[29].

The main inputs of a SCOD model are:

- A network representation. In particular the SO must select between an AC representation of the network and a DC-simplified representation. Furthermore, each network component could be modelled separately or some grouping could be implemented (for example, by representing the network as a collection of "zones", such that the transmission capacity among the nodes belonging to the same zone is assumed to be unlimited);
- A set of security constraints which includes, for example, the requirement that the solution of the model satisfies the "n-1" security criterion;
- Information about the demand at a level of granularity consistent with selected network representation;
- A timeframe for assessing the price of electricity; an hourly basis is commonly assumed, since it is consistent with the definition of the

product traded in the wholesale markets. In an alternative setting, it is possible to derive an approximation of the demand during different time periods (i.e. hours) by averaging. Averaging of demand across hours, however, it may cause a material loss of information, as many of the network constraints are binding only in relatively few extreme demand conditions that, when averaging, disappear;

- Information about the generation portfolio including, for each generator, start-up times, maximum and minimum output levels, ramp rates and the minimum time a generator must run once it has started. Generating unit costs are also included into the generation portfolio considered by the model and they contain, among others, fuel and non-fuel operating costs and the cost of environmental compliance;

- The standard objective function of the model is of a total surplus; traditionally, SCOD models are built on the assumption of limited or inexistent demand response to price changes; in this case the surplus maximisation problem boils down to generation cost minimisation. Short term demand elasticity can easily be integrated in the traditional SCOD models. Further, in a multi-year simulation setting, long term demand price elasticity can be accounted for.

- The model provides for the "optimal", or equivalently "market equilibrium", outcomes. Results of the SCODM include hourly predictions of the net injections at each node, variable costs of each unit dispatched, system marginal costs at each node, fuel consumption, emissions, flows across interfaces (e.g. cross border flows) etc.

As this brief description highlights, one of the advantages of the security constrained optimal dispatch approach is that it allows for a clear identification of the hypothesis

[29] For the welfare implications of some features of the spot market design prevailing in Europe, see, for example, Perekhodtsev D., Cervigni G. (2010) UK Transmission Congestion problem: Causes and Solutions. LECG report, January.

stated in terms of the evolution of installed generation capacity under different scenarios.

Next, we report a simplified mathematical representation of the security constrained optimal dispatch model. [30]

Call *d* and *g,* respectively, the injections and withdrawals at a certain node; let **country** = (**d-g**) be the vector of net real and reactive loads at all nodes. Each element of **country** is the sum of net withdrawals by all the consumers and generators at a certain node (**country** = $\sum \mathbf{y}_k$, where *k* is the index for the consumers and the generators). Let *country* be an index of the possible contingencies. For each contingency a set of constraints $\mathbf{K}^w$(**country**) ≤ $\mathbf{b}^w$ must be satisfied in order for the system to be safe and secure. $\mathbf{K}^w$(**country**) is the set of line flows, voltages and other variables, determined by the physical laws governing power systems.

b is the vector of the security limits for those flows, voltages and other variables. Let **K**(**country**) indicate the set of all the constraints in all the contingencies. "n-1" contingencies are often referred to in order to set security targets. In the "n-1" approach a contingency corresponds to the outage of one network element, and the corresponding set of constraints requires that during the outage the system keeps running safely.

Assume that each generator or consumer *k* has an associated net benefit function for electricity $B_k(y_k)$, which is concave and continuously differentiable. For consumers, the derivative of the benefit function is the standard demand function (corresponding to the consumers' bids); for each generator *k,* $B_k(y_k)$ is the cost function.

Having set the notations, the SCOD takes the form of the following optimisation programme:

$$\max \sum B_k(y_k)$$

[30] Harvey S., Hogan COUNTRY., Pope S. (1997) "Transmission Capacity Reservations and Transmission Congestion Contracts", pp. 41-44. William Hogan (2000) "Financial Transmission Right Formulations."

$$y_1,\ldots,y_n$$
$$s.t.K(\sum y_k) \le b$$

The main source of complexity of the SCODM is that network constraints are many and highly nonlinear.

The more accurate the set up of the SCOD model is, the more accurate will be its predictions and, therefore, the assessment of the value of the network upgrades. However , the choice of the software tools by the SO will reflect various considerations, ranging from the time and resources needed to set-up and maintain the models to the opportunity to use tools (and knowledge) already available, for example at the operations level. Furthermore, computational complexity may justify dealing with some types of benefits outside the core SCOD model.

We believe a reasonable approach would be to start simultaneously assessing, through the security constrained optimal dispatch model, the following benefits resulting from the network upgrades:

- Total generation cost;
- Cross-border flows;
- Ancillary service cost;
- CO2 emissions;
- Possibility to connect a renewable generation. Other benefits, such as reliability and losses could be assessed independently, at least in an initial phase.

The case of the California ISO, which has developed a comprehensive modeling framework in order to evaluate the future benefits of transmission network upgrades, is an example of the project that used SCODM. In the core of the CAISO transmission benefit evaluation methodology is the Optimized DC Power Flow model (DCOPF) PLEXOS. The PLEXOS model optimizes the dispatch of about 800 existing thermal, hydro, pumped storage and renewable plants with a total capacity of about

200,000MW plus expected additions[31]. The model optimizes in an integrated fashion the dispatch of thermal generators and energy budgets of pump storages and hydro units. The model accounts for scheduled generator outages and models random forced outages. The model however does not explicitly account for generator unit commitment costs and constraints[32]. The model uses a detailed network representation of the WECC and computes physical flows over 17,500 lines and allowed calculating nodal prices in 13,400 nodes[33]. The OPF includes optimization of phase shifters and DC line flow, and models transmission interface limits and custom monograms.

In the next section, we provide more details on selected issues involved in the set-up of a security constrained optimal dispatch model for the evaluation of transmission upgrades.

4.1.1 The Transmission Network Model and the Market Model

Core features of the European wholesale electricity markets design are:

- A high level of geographical standardisation of the traded product;
- Separate spot energy and ancillary-service-procurement markets.

The first feature implies that there is no price differentiation across locations within each country[34]. No network-related constraints limit the flexibility of market participants in carrying out their transactions or, more precisely, in selecting the generating units that will be activated to honour the commitments resulting from their transactions. In other words, the network representation implicitly assumed for the purpose of market clearing has unlimited capacity (so-called "copper-plate" assumption). As a result of such a market design with unconstrained market clearing, notified injections and withdrawals may result in flows violating one or more security constraints. As we mentioned in the previous section, the alternative approach,

31 CAISO, "Economic Evaluation of the Palo Verde-Devers Line No. 2 (PVD2)", February 2005 (PVD2), p. 11
32 TEAM p. 2-6
33 PVD2 p. 9

extensively applied in the US, consists in implementing a market clearing algorithm producing a market outcome compatible with all the relevant operational constraints.

As for the second feature based on the fact that schedules notified by the market participants after the trading and on a set of bids and offers submitted by the generators (and in some cases by dispatchable loads), the SO purchases ancillary services, typically, in the form of:

- Start-up of generating units;
- Reservation of capacity margins;
- Changes in selected generators' schedules.

Ancillary services are procured to solve congestions, make available adequate reserve margins, maintain a continuous equilibrium of injections and withdrawals or, more generally, to ensure safe and secure operations of the system.

In the current market design, hence, a transmission network upgrade that does not impact cross-border capacity is not reflected in the market outcome, since the electricity market clears in this setting under the unlimited transmission capacity assumption. Only the outcome of the ancillary service procurement mechanism reflect the changes to the network resulting from the upgrade.

We describe next two approaches to model the network, in this context, with the purpose of assessing the impact of energy transmission infrastructure upgrades.

4.1.1.1 Option 1: Modelling the existing institutional framework

This approach of estimating the impact of transmission upgrades on the constrained optimal dispatch mirrors the actual institutional setting by assessing the effect of the network upgrade first on the market outcome, and then on system operation costs.

In broad terms the methodology would entail the following steps. First, the impact of the network on the electricity market outcome is assessed. Since the "copper-plate"

[34] With the exception of Italy, Sweden, Denmark, Finland and Norway, where a zonal market design is

assumption is maintained for market clearing purposes with the exception of cross-border transactions, the only potential impact of the network upgrade on the market outcome results from a change in cross-border interconnection capacity.

The effect of the network upgrade on available cross-border interconnection capacity is assessed by running a security constrained optimal dispatch model; this calculation should be consistent with the general methodology adopted to calculate the cross-border capacity in operations. In broad terms, the methodology for cross-border capacity calculation currently implemented by the European SOs consists of first establishing a base case scenario of generation schedules and consumption patterns throughout the system. Then the Total Transfer Capacity between two areas is calculated as a maximum interchange that does not violate any transmission constraint including contingency constraints while the base-case schedules in the rest of the grid are kept fixed. The calculation of the Total Transfer Capacity uses the full AC network model to account for indirect flows resulting from the base case power schedules and the interchange between the two considered regions. The calculation of the Total Transfer Capacity is performed at different base case scenarios of generation and consumption and the most conservative transfer capacity value is eventually used as cross-border Net Transfer Capacity.

The new level of Net Transfer Capacity is an input in the market simulation model, run under the assumption of unlimited transmission capacity within the country. The results of this simulation are: the new equilibrium (commercial) cross-border flows and the new market outcome (in terms of price and total quantities). Based on the simulated market outcome – and on estimates of the generators' costs – it is possible to estimate the minimum cost generation schedules corresponding to the simulated market outcome.

The first stage would then allows to estimate the effect of the network upgrade on the market outcome (electricity prices and total quantity produced and net-imported in the country), as well as the change in the "unconstrained" generation costs.

implemented.

In the second stage, a detailed AC network model is applied to test for feasibility of the set of schedules obtained in the first stage. The model used at this stage should be consistent with the SO's usual approach of finding optimal redispatch solutions and/or of procuring ancillary services.

Changes in the generators' injection programs performed to guarantee safe and secure operations of the system are chosen to minimize total costs. The difference between the production costs resulting from the market-based schedules (obtained in the first stage) and the production costs resulting from the security constrained (optimal) dispatch, constitutes a cost born by the SO (and further passed through to customers). The difference between this cost in presence of the upgrade and without the upgrade represents the benefit from the upgrade due to reduction of system operation costs.

4.1.1.2 Option 2: Full Network Model

The alternative approach in estimating the effects of the network upgrade consists in modelling a nodal market by performing a constrained optimal dispatch using the full network model as a power flow constraint and calculating locational marginal prices in each node equal to the marginal cost of delivering an additional MWh into that node, while satisfying all the relevant security constraints. In presence of transmission constraints the solution of such model would result in different prices in all generator nodes reflecting the different impact of injections of these generators on the transmission constraints. The model results in the optimal solution which minimizes, simultaneously, generation and ancillary services costs. Incidentally, this approach is used in the US to clear the energy (day-ahead and real-time) markets.

As discussed in Section 4.2, the SCOD model provides information on the minimum-cost dispatch of electricity. Therefore one can consider the SCOD outcome as the final outcome that would result, in the current institutional setting, after:

- Market participants have notified their intended generation schedules;
- SO redispatch actions and procurement of ancillary services have been performed.

In order for this equality to be maintained, one needs to assume that market participants are rational and well informed, so that the dispatch resulting in the current market design coincides with the one that would be computed via the security constrained optimal dispatch model. There are no barriers in the design of the energy and ancillary service markets preventing the efficient allocation (reallocation) of the existing generation resources among the different services.

4.1.1.3 Assessment

The first approach – mimicking the current institutional setting - is attractive to the extent that it allows to model specific features of the current market design that might cause departures of the market outcomes from the efficient benchmarks, and to the extent that those specific features are believed to remain in place in the relevant time horizon.

Another attractive feature is that the results provided by this methodology correspond immediately to elements of the current institutional setting (i.e. a uniform market equilibrium price, SO-costs, etc.), which makes the methodology easier to understand by the interested parties.

The second approach requires running less optimization and power flow analysis than the first one, thus allowing to capture all aspects of the market from a single run of the constrained optimal dispatch model.

Another advantage of the full network model is that in the context of such model it could be easier to detect and account for market power. Some generators may enjoy market power because of their location on the network. Under the current institutional setting, the exercise of market power by these generators might entail implementation of the complex bidding and scheduling strategies that could be difficult to model in the two-stage approach. The nodal model, however, allows the assessment of the competitive position of a generator in a relatively straightforward way, by analysing the relationship between the generator's bid-cost and the price at the generator's node. This makes it much easier to identify market power positions that could be particularly useful when one decides to deal with "off model" market power.

4.2 Accounting for the impact of market power

So far the level of the generator price bids used in the modelling of the market has been assumed to be reflective of the generator's variable cost. However generators may enjoy market power, i.e. they may have the ability and the incentive to alter prices away from competitive levels. Binding transmission constraints within a single coordinated market result in fragmented geographic sub-markets, in which market concentration is often higher than at the broader market level. Thus, transmission upgrades may generate benefits by expanding geographic sub-markets and thus decreasing generators' market power.

We considered two broad alternative approaches in order to assess market power for the purpose of assessing the value to network upgrades. The first approach entails modelling, within the SCOD model framework, the strategic interaction among generators with market power. A discussion of the theoretical frameworks developed for the analysis of the strategic interaction among generators is beyond the scope of this project and we refer the interested reader to the rich literature on that subject[35]. We limit ourselves to recalling the complexity involved in modelling the bidding strategy of generators with market power and the existence of multiple equilibria. Therefore, we build our proposal around the alternative approach, consisting in: a) calculating measures of market power of each market player and b) applying bid mark-ups that reflect the market power measured by those indicators.

4.2.1 Structural measures of market power in electricity markets

Structural measures of market power are used to assess the ex-ante potential of market power exercise (that is, before such exercise actually occurs). This type of analysis is common whenever assessing the competitive effects of, for instance, proposed mergers, acquisitions, of market deregulation, etc.

General competition policy commonly applies structural measures of market power based on market shares of participants, However, when applied to electricity

[35] Pioneering models of strategic interactions in the wholesale electricity market are: 1) Newbery, D., Greene, R. (1992), Competition in the British Electricity Spot Market, The Journal of Political Economy, Vol. 100, issue 5, pp. 929-953. 2) Von der Fehr, N.COUNTRY. and Harbord, D.(1993), Spot Market Competition in the UK Electricity Industry, The Economic Journal, Vol. 103, pp. 531-546.

markets, the index fails to provide meaningful results due to the nearly zero demand elasticity[36].

Structural measures that are more relevant for electricity markets are generally based on some measure of the degree to which a generator is indispensible or "pivotal" in meeting demand, that is, whether the demand can be met without relying on the capacity of that generator. Several concentration measures have been devised based on the pivotality of generators and are applied in electricity markets. These measures include Pivotal Supplier Index (PSI) and Residual Supplier Index (RSI). The former is a binary indicator of whether demand can or cannot be met without the capacity of a given generator, that is, whether the generator is "pivotal" in meeting the demand[37]. The latter is a continuous rather than a binary measure of "pivotality" of particular generators. The RSI is calculated as the ratio of the available capacity, excluding the capacity of a given generator, over demand[38].

These or similar indices are widely adopted to assess market power in electricity markets. They are used by Independent Market Monitors surveying the competitiveness of electricity markets in the US; these indices also become more and more important in the assessment of the competitive effects of mergers in the electricity sector.

4.2.2 Measuring market power in the presence of constraints

The measures of generators' market power based on pivotality can be adapted to be used in the context of transmission constraints. We will discuss two methods here: one is a method measuring pivotality in relieving particular constraints, widely used in several US markets, and the other is a generalization of this method.

In the wide-area regional markets of the U.S., such as the PJM and the Midwest, the system-wide market power is of little concern because the overall concentration of generators is small, while locational market power is of more concern. Therefore, the

[36] Borenstein, S., Bushnell, J. and Knittel, C. (1999), Market Power in Electricity Markets: Beyond Concentration Measures, Energy Journal, vol. 20, issue 4.

[37] Borenstein, S., Bushnell, J. (1999), An Empirical Analysis of the Potential for Market Power in California's Electricity Industry, Journal of Industrial Economics, Vol. 47, issue 3, pp. 285-323.

operators of these markets screen the effect that each generator may have on transmission constraints and measure how "pivotal" generators are in causing congestion[39]. This is done by analyzing separately the components of the flow over each constraint. The linearized effects of each generator node on the constraint (Power Transfer Distribution Factors or PTDF) are used to evaluate the potential impact of each generator on the flow over a given constraint. A particular generator is found pivotal relative to the constraint if it has a capacity to cause congestion by withholding its capacity (or otherwise forcing its capacity) given that the remaining generators act at their best capacity (supplying power at maximum capacity or setting the output to zero depending on the sign of their effect on the constraint) to relieve that congestion.

Such measure of pivotality relative to individual constraints is easy to compute by using PTDFs, constraint limits, locational demand levels and generators' capacities. However, this measure has two drawbacks. First, the method evaluates the pivotality relative to individual constraints but provides no insight about the market power created simultaneously by all existing constraints. Second, the effects of power injections on the flow over constraints described by PTDFs are given relative to a reference node, that is, an assumed destination of power injections. The choice of the reference node has no effect on the market solution in which PTDFs can also be used, but it may have a significant effect on the measurement of pivotality relative to constraints using the method described above. The impact of the choice of the reference node can be slightly alleviated if the distributed reference node is used (that is, a node that is a load-weighted average of all system nodes).

The constrained pivotality estimation can be generalized to address these drawbacks. For example, one may directly estimate the extent to which demand can be met without the capacity of a given generator while satisfying the transmission constraints. For that purpose, an auxiliary constrained optimal dispatch model should be performed. In this model the injections of generators are chosen to minimize the total output of a given generator while meeting both demand and transmission

[38] Sheffrin, A. (2001), Effective market monitoring in deregulated electricity markets, Transactions on Power System, vol. 18, issue 2, pp. 486-493.

constraints. If, as a result of the optimization, the output of the given generator is positive, it means that the generator is pivotal to meeting the demand given the transmission constraints. This method can simultaneously account for all constraints and does not depend on the choice of the reference node.

Any of the above mentioned methods can be applied to measure the impact of any network upgrade on generators' market power. If the full network model is used in the context of the regional market, these methods would make no distinction between market power with respect to inter-national or intra-national constraints. Market power analysis with respect to physical constraints would allow the most accurate measure of the impact of the network upgrade on market power.

4.2.3 Relationship between market power and bid mark-ups

Once a reliable structural index of market power has been identified and computed, the relationship between that index and the generators' bidding behaviour must be established. That will allow assessing:

- The impact of the network upgrade on the market power of each generator, by calculating the value of the index "with and without" the network expansion
- The supply functions accounting for each generator's market power "with and without" the network expansion.

These supply functions can then be used – instead of the variable cost functions - as an input to the SCOD model to assess the welfare effect of the network upgrade.

The relationship between generators' pivotality (relative to constraints) and the bid mark-up of these generators may be investigated empirically.

For example, in California, the Market Surveillance Committee has been studying the relationship between the hourly Residual Supplier Index and the hourly price-cost mark-up. They have found a strong linear relationship between the two variables: this

[39] Casey, K. (2006), Prepared Direct Testimony. Docket No. ER06-615-000, before the Federal Energy

means that the higher the pivotality, the higher the mark-up[40,41]. This relationship is used for many competitions and regulatory purposes in California. The relationship between market structure and market behaviour established in California may be specific to the generation fleet and structure of that particular electricity market and may not be transferable to other markets.

Using regression techniques the CAISO has established a relationship between the mark-up of the zonal price over the estimated marginal cost and the pivotality of the largest supplier in a given zone measured by the Residual Supplier Index (RSI), as well as the Percentage of Unhedged Load (PUL) of that generator and seasonal and daily peak dummies. The measures of market structure, RSI and PUL, are calculated in each of the three Californian zones: SP15, NP15 and ZP26.

Overall, the empirical approach of market power identification is applied with the following steps: First, regression identifying the relationship between zonal price-cost mark-up and the RSI is established. Second, parameters of the zonal market structure are assessed in each hour and each zone: RSI, identity of the largest single supplier, total uncommitted capacity of the largest supplier, and zonal load. Third, regression equations are applied to the system parameters while the estimated price-cost mark-up is applied to the competitive generators' bids in each zone in order to compute market clearing prices.

4.3 Assessing reliability and losses

The main advantage of assessing the benefits of transmission upgrades through a SCOD model is that the interdependencies among the different types of benefits are fully accounted for. However, the features of the modelling tool selected by the SO for network planning purposes may reflect other considerations, ranging from computational complexity to the ease of maintenance of the model, or even familiarity with certain tools already in use in the company for other purposes.

Regulatory Commission.

[40] As reported by Newbery, Green, Neuhoff and Twoney (2004), "A Review of the Monitoring of Market Power", Report prepared at the request of ESO, page 28.

[41] Sheffrin, A. (2002a) "Predicting Market Power Using the Residual Supply Index" Presented to FERC Market Monitoring Workshop December 3-4, 2002.

One possible simplification of the SCODM is the so-called “DC-representation” of the network. The advantage of this approach is that the optimisation problem is dramatically simplified, since the network constraints become linear. The price to pay is some loss of information, in particular on the impact of the voltage constraints and on the computation of power losses.

In that case, the assessment of the effects of a network upgrade on system losses can be estimated outside the SCOD Model. The natural way is to plug the injection/withdrawal programmes resulting from the SCOD model with and without the network upgrade in AC power flow model and assess losses in both cases. AC power flow models should be readily available to the SO, as they are used daily for security calculations.

Similarly, external analysis to the SCOD model could be used to assess the impact of network upgrades on network reliability. This may be necessary if the reliability analyses are performed through very computation intensive methodologies. We understand that Monte Carlo simulations of the lost load are commonly used by SO’s to assess network reliability. Failures of network elements are simulated based on the past outage frequencies. This allows calculating a probability distribution function of the lost load with and without the network upgrade.

Two important assumptions, when performing this kind of assessment are:

- The value of lost load – i.e. the price that customers receiving electricity with firm contracts would be willing to pay to avoid a disruption in their electricity service; and

- The metric to assess reliability; for example one could consider the expected value of lost load as the relevant measure or reliability, or some indicators of the shape of the lost-load probability distribution function (for example, for the same expected level of lost-load, a relative uniform probability of losing the average amount might be regarded as different from a situation when very large service disruptions occur in a very limited number of extreme instances).

4.3.1 Benefits from avoided network costs

Avoided network costs are costs that SO would bear if the network upgrade under examination did not take place.

A typical case of avoided network costs is when, by building a new transmission line, the SO avoids building a new substation, which would have been otherwise necessary to satisfy the (growing) load.

Including this, the benefits in the assessment of the impact of the network upgrade are straightforward.

4.4 Scenario selection

The benefits of transmission expansion should be evaluated under many scenarios. A large number of scenarios is needed for both an accurate estimation of the expected benefit and the expected range of benefits. Some of these scenarios reflect the variation of short-term system conditions, such as daily, weekly and seasonal demand variation and availability of generating and transmission capacity, as well as seasonal variation of major input variables. The other group of scenarios deal with the risks and uncertainties about the future values of major input parameters: load growth, fuel costs, additions and retirements of generation units as well as the location of those generators.

4.4.1 Addressing short-run system variations

Short-term variations in the system conditions can be addressed by modelling market outcomes over all hours of a scenario year. Within such a model, daily, weekly and seasonal demand variations can be addressed by using the historic locational demand data, scaling them up by the projections of the demand growth. The historic statistics of outages of generator capacity and transmission elements can be used to simulate generator and transmission availability in each hour of the modelled scenario year. Historic annual variation of fuel prices and hydro levels can be used to account for the seasonal variations in the forecasted levels of these variables.

Performing market modelling for each hour of the scenario year may turn out to be a computationally intensive exercise. In this case, computational time can be reduced by aggregating hours with similar system conditions.

4.4.2 Addressing long-term uncertainty

To account for the uncertainty regarding long-term development of future conditions, several annual scenarios should be performed reflecting different combinations of possible levels of major input variables. However, given multiple variables and multiple possible values for each variable, the total number of all possible variable combinations (scenarios) can be very large. Due to the computational time needed to perform each annual scenario, one does not need to simulate all possible scenarios, limiting the number of scenarios by using sampling methods.

First, for each major input variable one might use a limited number of levels representing the most likely future value as well as the extreme expected future values. However, if the number of input variables is significant, the number of scenarios representing all combinations variables levels can still be too large.

For example, one might consider accounting for uncertainty in the following input variables: price of natural gas, price of coal, price of CO2, peak demand, hydro levels, the level of economic entry, and the extent of strategic behaviour. However, even if only three values of each variable are considered (the most likely value and two extreme values), the number of combinations of all levels of these seven variables is over 2000. In this case, the number of scenarios for benefit evaluation may be reduced using standard methods for sampling from multi-dimensional distributions. For example, the Latin Hypercube Sampling can be used since it is proved to produce samples that are representative of real variability.

To calculate expected values of benefits across all modelled scenarios, each scenario is attributed a probability based on the joint probability of the input variables used to construct this scenario.

For example, CAISO uses a scenario analysis with stochastic components to account for the uncertainty of the future values of these parameters. Representative scenarios have been identified based on several values of the input variables. For load level, gas prices, and bid mark-ups resulting from market power exercise five values have been identified: a base case value representing the best forecast point estimate, a high and low values representing upper and lower 75% confidence bounds of the forecasted values and very high and very low values representing 90% confidence bounds of the forecasted values. In addition, the model considers three values of hydro production levels (namely Wet, Base and Dry), and three values of new entry of economic generation: Base, Overinvestment (50% above the base) and Underinvestment (50% below the base). Each combination of values of input variables represents a separate scenario.

CAISO then employs two sampling methods to obtain a representative sample from all available scenarios: the importance sampling and the Latin Hypercube sampling. These sampling techniques allow reducing the number of runs of the optimal dispatch model while covering the entire range of values of input variables.

CAISO then uses a Moment Consistent Linear Programming model to assign joint probabilities to the selected scenarios. This method assigns probabilities to each scenario determined by the combination of the values of input parameters so that it matches the probability distributions of each of the input parameters: gas price, demand, and bid mark-ups[42].

4.4.3 Modelling entry in generation

The amount, location and timing of new operators' entry may greatly affect the value of transmission expansion. Therefore the evolution of the generating fleet is a crucial input to assessing the value of transmission upgrades.

Market simulation should use all the information available to the SO on planned generation investments, like location, type, size, and expected time of commissioning of the proposed new generating units as well as the expected time of the retirement of the existing units. This information is generally available for at least several years

[42] TEAM, pp. 5-1 to 5-9

in the future. An increasingly important information is the potential for renewable electricity generation in the different areas.

Furthermore, modelling the energy market in the future “with and without” the network upgrade requires accounting for the interdependence between network development and generation localisation decisions.

However, beyond these planned additions, the impact of transmission expansion on energy prices may create additional incentives or disincentives in order to invest in generation in particular locations.

The Entry of generating capacity can be assessed through the following iterate process:

- Market simulation without a new generation is run for the chosen scenario over the study time horizon.
- The Resulting price distribution in each location (zone) is examined. If the average price during hours when price is above the marginal cost of a standard generating technology (e.g. CCGT or SCGT) exceeds the annual revenue requirement of this technology, the entry of a unit of corresponding technology is assumed. The market simulation with the new entry is performed and a new set of prices is calculated. The amount of economic entry of standard generating technologies is adjusted up to the point at where no new unit is profitable.

In addition to the optimal generator entry calculated as described above, several alternative entry scenarios can be considered representing possible under- or overinvestment relative to the optimal economic investment level.

For example, The CAISO methodology addresses the interdependence between the generating capacity and the transmission capacity. Apart from taking into account new generating capacities based on submitted interconnection requests at the moment of the study, the CAISO methodology explicitly models the future expected economic entry of generation capacity.

For each transmission upgrade option a pattern of long-term new generation entry is derived under the assumptions that any new entry is independent and non-strategic. Two generating technologies are considered for entry: peaking gas-fired SCGT units and base load CCGT units.

The model verifies whether market prices predicted in each zone (accounting for strategic bidding) would trigger entry of new units of either one of these two types by comparing annual revenues that could be expected by such a unit with its annualized capital cost. The model would assume that entry would occur until the model converges to a point where new entry is no longer profitable. Such long-term entry is derived separately for each transmission option. Entry decisions are based on the probability-weighted average of prices for three different demand scenarios reflecting the fact that entry is based on expected profits under a variety of system conditions[43]. The equilibrium entry derived as described above constituted the base case generation entry scenario.

[43] CAISO & LE pp. 42-44

5 Evaluation of natural gas transmission investments

In this chapter we address the methodology to assess costs and benefits of a gas transmission upgrade. The general framework for a cost-benefit analysis of a gas transmission investment does not conceptually differ from the one that we have discussed for the electricity sector. In particular for gas as well as for electricity the value of a transmission upgrade is, in general terms, the net-surplus of the additional transactions that can be carried out after the upgrade. Therefore assessing the value of a network upgrade requires identifying the set of additional transactions generating the highest net-surplus made feasible by the upgrade.

However, the specific economic and institutional features of the gas industry require significant departures of the methodology to assess the value of the transmission upgrade from the one developed in Chapter 4 for electricity.

The first specific feature of the gas industry is that most of the gas consumed in Europe is imported from non European countries. Therefore if the SOs and the Regulators are to act on behalf of the European citizens the welfare notion relevant for the assessment of the gas transmission upgrades should not include the producers' profits. In practice that means that the cost-side of the welfare function should not reflect the gas production—costs but the gas procurement price assessed at the European borders.

The second feature is that long-haul transmission infrastructures are usually idiosyncratic to investments in gas production. For those investments the merchant regime appears to be the most suitable, as investors need to control access to the transmission capacity to reap the benefits of their investment in production over the relevant time frame. We therefore expect elements of the merchant model to prominently feature in the gas industry

The third feature specific of the gas industry relates to the trading arrangements. The liberalization of the European gas markets has not yet displayed its impact in full. This depends on various elements, including the fact that Third Party Access and the Use It Or Lose It (UIOLI) provisions on the existing international pipeline are not yet fully effective. In addition, wholesale spot gas (and transmission capacity) trading within Europe are still limited, because of contractual and/or regulatory frictions inherited from the past. Improvements of those areas of the regulation framework may dramatically modify the assessment of the opportunity of some transmission upgrades. Therefore the value of additional transmission capacity cannot be assessed under the assumption that the regulatory framework, as we see it now, is stable.

Finally, forecasting the future transactions of gas in order to assess the value of gas transmission upgrades is very difficult, given the lack of transparency of the market and the nature of the transactions. Predicting the electricity production (and cost) at each location is – at least conceptually – relatively easy, once one has predicted the evolution of demand and of the installed generation capacity. On the contrary gas transactions, in particular at the production level, depend from many conditions – related to the global economic and to political environment – whose prediction is a highly risky exercise.

For these reasons it is crucial that the methodology which is used to assess the value of gas transmission upgrades is designed in a way that allows the SO and the Regulator to extract the greatest possible deal of information from the market. For this reason we have developed our proposal around a hybrid institutional setting, that appears to compatible with the Directive 73/09, in which the assessment of the value of the gas transmission upgrades is based on the availability of market investors to take on some of the corresponding risk.

5.1 Assessing the benefits and costs of the gas network upgrades

In this section we will discuss the role and on the scope of the cost-benefit analysis of gas transmission investments under alternative settings. We start by illustrating, in section 5.1.1, the traditional central planning framework. In section 5.1.2 we outline a setting allowing the SO to extract the information on the value of the incremental transmission capacity from the market; we characterise this setting as a hybrid model since it brings elements of the merchant model to the central planning approach. The analysis is first carried out without taking into account the pro-competitive impact of new infrastructures and security of supply concerns. These issues are then analyzed, in the two following sections 5.2 and 5.3. The value of environmental externalities is discussed in chapter 6, for both electricity and gas infrastructures.

5.1.1 Assessing network upgrades in a central planning framework

In Chapter 3 we have characterized central planning as the institutional setting in which network development decisions are taken by the SO. The corresponding risk is placed on end-customers, which pay transmission tariffs ensuring full cost recovery of the investments, irrespective of the assets' actual degree of utilization.

In that framework the SO has the responsibility of forecasting the future requests for transmission rights and the corresponding gas flows. Based on those forecasts, the SO plans the least-cost network developments that allow it to issue a feasible set of transmission rights meeting (expected) demand.

Forecasting the demand for transmission rights requires forecasting the market outcome, as we already discussed concerning electricity in Chapter 4. The additional complication in the gas sector, compared to electricity, is that estimating the market outcome in, lets say, one country, entails the forecasting of the outcome of a much wider market, at least European and to some extent worldwide. Predicting the gas flows across a central European country requires assessing the procurement sources of all the surrounding countries and, ultimately, how supplies to Europe will be shared among the main producers. Moreover, in the gas sector we don't know the production costs at each "location" and we need to estimate the complex relationship between costs and prices. Even though the methodological procedure to identify possible market outcomes in a centralized approach if in principle formally similar to the Optimal Dispatch Model proposed for the electricity sector, in practice the uncertainty about input variables and behavioural assumptions is much higher in the gas sector. Codifying a methodology to assess the value of a transmission system upgrades is therefore not easy, as many interrelated variables are involved in the assessment. Following, we describe just one of the possible ways to organize the analysis.

The starting point of the assessment is a forecast of the European demand of natural gas. Forecasting the European gas demand does not appear a much different exercise from the one traditionally carried out by the national monopolists for planning purposes. We incidentally notice that the new EU climate and energy policy might result in a structural break in the evolution of demand, that should be reflected in the assessment.

The second stage consists in developing a reference scenario[44] on the sources of supply to Europe. Several issues enter the assessment of the future sources of the gas to Europe, including:

- The evolution of the world-wide gas demand and supply balance. At this level, one would assess the effects of, for example, the expected evolution of the gas demand in Asia, and, at the supply side, the available reserves of unconventional gas in the different areas, and the available LNG gasification and shipping capacity;
- The exploitation strategy of each producer's endowment and the competitive interaction among the producers. Issues that are relevant at this level are, for example, the possibility that a cartel agreement is reached (and maintained) among the main suppliers, the political situation within each producing country;
- Production and transmission costs for each supply option.

We suggest developing the reference supply scenario on the basis of the set of infrastructures existing or planned at the time the analysis is carried out.

Third, the results of the previous assessment allow the identification of the need-for or the opportunity-of expanding the set of transmission rights made available to the market. Consider the following situation for example: an increase demand in Asia is expected to put pressure on the Russian supply but, given the current transmission

[44] The assessment requires developing and comparing the effects of different scenarios. For simplicity of exposition we present the methodology with reference to one scenario only. Furthermore, we neglect a crucial element of the analysis, namely the retroaction of the results of each stage on the assumptions on which the previous stages are based.

infrastructures, the possibility to move North-African gas to central-Europe is limited. That creates the potential for a price difference between Russian and North-Africa gas supplies to Europe. By expanding the transmission capacity from North-African to Central Europe, North-African supplies can compete with the (scarce) Russian gas in Central Europe.

We notice that this step of the decision-making process is intrinsically multi-national, since typically additional transmission rights of different SOs' networks will be needed to obtain a material impact on the market outcome.

The final step consists in identifying the network upgrades necessary to make each additional set of transmission rights feasible at the minimum cost[45]. It is finally possible to compare the costs and benefits of each set of additional sets of transmission rights. The investments should be realized as long as the present value of the related cost is lower than the present value of the additional transmission rights made available to market participants. The following Figure illustrates the decision-making process in the centralized planning framework.

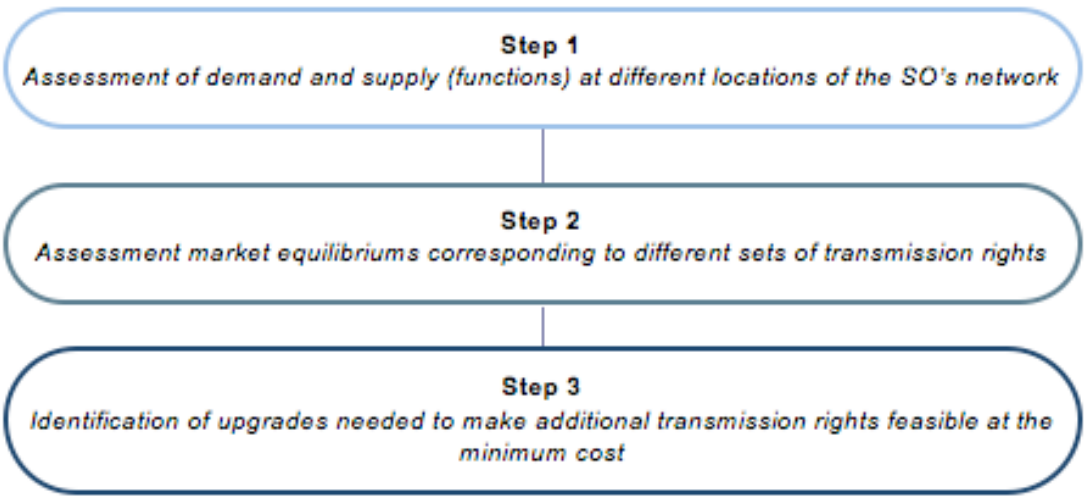

Figure 5.1: Decisional steps in the central planning approach.

This kind of assessment is very debatable. Not only most of the determinants of the reference scenario are highly uncertain, but the relationship between the reference scenario and the value of gas at different locations – the ultimate determinant of the benefit of the transmission investments – is very weak. This structural weakness of a pure central planning approach motivates our research for an alternative setting, which relies on the market to assess the value of additional transmission capacity.

Before turning to the discussion of the alternative setting we notice that the fact that, in the planning setting the investment risk is placed on the final customers creates additional issues. The SO, acting on behalf of the customers located in the area under her control, will want to take an extra-prudent stance with respect to investments on assets that are expected to be used to mostly export gas. In Chapter 7 we argue that transmission capacity expansions might adversely affect the customers located in the exporting countries and that might discourage a "nationally-minded" SO form investing.

We do not develop that line of reasoning here. We just notice that it is debatable that the SO should commit the end-consumers to even pay for transmission investments supporting exports or transits that would not cause any wealth transfers[46], whose value would be eventually appropriated by the same customers[47]. The debatable element, in this policy, is that the SO would be committing the end-customers to a speculative investment.

5.1.2 Extracting from the market the information on the value of network upgrades

In Chapter 3 we have characterized the merchant framework as the institutional setting in which private investors invest on and own network assets. The SO allocates to the asset's owners a set of transmission rights with duration equal to the life of the assets. The entire investment risk is placed on the investors.

In a pure merchant framework there is little room for public intervention. However,

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45 For a discussion on the relationship between capacity upgrades and transmission rights we refer to Chapter 3.

46 That would happen for example, if final consumptions were fully hedged by long term supply contracts. See Chapter 7.

47 Which would for example be the case if the resulting transmission rights were priced "at value" and the corresponding revenues were passed on to the end-customers.

elements of the merchant logic can be introduced in the planning setting in order to extract form the market as much information as possible on the value of the transmission upgrades.

The result is a hybrid setting, in which the SO acts as the aggregator of the market's demands for additional transmission rights. In this framework the advantages of a centralised approach, in terms of coordination and full exploitation of scale economies, are retained. However the resulting risk allocation is closer to the one that would result in the merchant model, as market investors bear part of or the investment risk, as they commit to purchasing the additional transmission rights over a given period of time.

The decision-making process in this hybrid setting can be summarized as follows. First the SO runs "open seasons" from time to time, allowing market participants to express their demand for additional transmission rights. This stage of the process can be organized in different ways. The more reliable and complete is the information obtained by the SO the less iteration between the SO and the market will be necessary to identify the equilibrium outcome (see below). In the following paragraphs we will assume for simplicity that market participants truthfully reveal their preferences at each stage of the process.

In the second stage of the process, the SO determines the minimum cost of making the set of transmission rights required by the market available. This information is conveyed to the market participants, for example in the form of:

- The level of the tariffs that will be charged for the additional transmission rights and
- The minimum number of years for which the additional transmission rights must be purchased.

Based on that information, market participants have the possibility to revise their request for additional transmission rights and, based on the revised requests, the SO determines again the minimum cost of making the required set of transmission rights available. The process continues until convergence, i.e. until the market participants commit to buying the set of additional transmission rights offered by the SO. The following Figure illustrates the decision-making process in the hybrid framework.

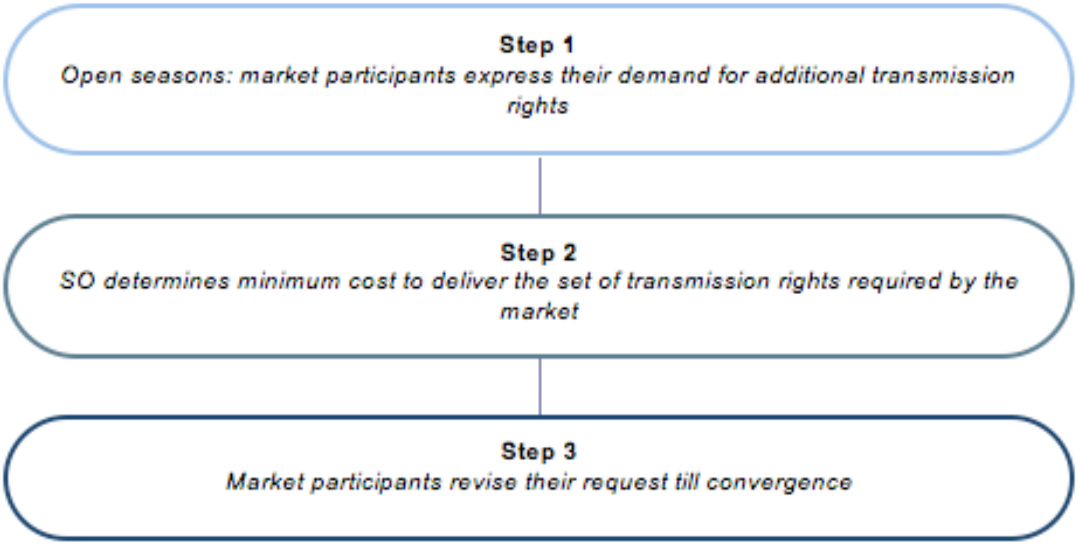

Figure 5.2: Decisional steps in the hybrid approach.

The description of the investment decision-making process in the hybrid framework allows to highlight the differences between this framework and the merchant one. In particular, under the following three conditions the central coordination framework can be regarded as an improved version of the merchant approach:

- The price for the incremental transmission rights reflect the incremental cost of making those rights available;
- Market participants are required by the SO to commit to purchasing the additional transmission rights on a time-span allowing the SO to cover the entire cost of making those rights available;
- The SO is as efficient as market investors in building the infrastructures that are needed to make the additional rights feasible.

The first two conditions cause the position of the buyers of the additional transmission rights similar to that of the owners of a merchant project. The third condition makes investment costs the same in the two settings. If all conditions hold the centrally coordinated system can be expected to yield better results.

Regarding the first condition, we notice that in some European countries, where mechanisms based on open seasons are implemented, market participants are asked to pay tariffs that are only imperfectly reflective of the incremental costs. For example, transmission tariffs typically reflect some averaging of the costs of the different vintages of investments. To the extent that the prices for the additional transmission rights depart from the incremental cost of supplying them, distortions may result. The relevance of those distortions is a matter for empirical investigation.

We incidentally notice that this approach would ease, compared to central planning, the allocation of any common costs among the different types of new transmission rights created by the network upgrade. When the market participants express their availability to buy the new transmission rights resulting from the network upgrade they reveal their availability to pay for each type of rights. That allows the SO to identify the (set of alternative) allocations of the common costs across the different transmission rights that allow covering the upgrade's cost.

Consider for example the case in which a network upgrade allows to simultaneously create new entry capacity at two different nodes and the market shows a high availability to pay for the incremental entry capacity at only one of the two nodes. In this case it is efficient to place a higher share of the investment costs on the entry capacity at high-valued node. If the information about the market's availability to pay for the different transmission rights was not available, then the allocation of the common costs across the different types of transmission rights would have to follow some conventional rule, for example a uniform per Bcm-year charge at all the entry points. If that resulted in a more symmetric sharing of the common costs, the revenues obtained by selling entry rights in the high-valued node would decrease and the revenues from the low-valued node would not increase, as the demand for rights at that node would be reduced. Total revenues could then fall below the investment costs and a desirable investment would not be undertaken.

The advantages of pricing the new transmission rights based on their market value would be even greater in the presence of a liquid secondary market for those transmission rights, as in this case no rents would be appropriated by the assignees of the new transmission rights.

With regards to the second condition, SOs sometimes finds it difficult to obtain from market participants the very long-term commitments necessary to hedge the full cost of the additional transmission rights. In that case, if the investment is carried out, part of the risk that its value turns out to be lower than its cost remains on the SO and, via the tariffs, on the final customers. That brings the forecasting issue back into the picture, to the extent that the SO needs to assess the value of the transmission rights that cannot be allocated in the open season, against the corresponding costs.

More generally the hybrid framework appears to be suitable in implementing a mixed decision-making approach, where network upgrades reflect both the market demand for transmission services and the broader objectives pursued by the SO. In the next two sections we turn to the analysis of those broader objectives

5.2 Assessing the impact of gas transmission investments on competition

It is generally recognized that an increase in the transmission capacity is likely to increase competition among suppliers. A new transmission line can enhance market competitiveness by increasing both the total supply that can be delivered to consumers and the number of suppliers that are available to serve the wholesale market. This can, in turn, limit the suppliers' ability to manipulate prices in the downstream market.

In section 5.1 we highlighted the difficulty in assessing the impact of a transmission upgrade on the gas market outcome. This led us to stress the importance of extracting from the market as much information as possible as to the value of the transmission upgrades.

In the hybrid model developed in the previous section competition in gas supply itself is the main driver of the private investors' decisions to take the risk of purchasing long term transmission rights, in the open season process that leads to the investment decision. For example, a high price differential between two countries – in a situation of scarce transmission capacity – creates the opportunity to buy gas in the low-price country, buy additional transmission capacity from the low-to the high-price country in an open season, and sell in the high-price country. In this setting the assessment of the competitive effects of transmission investment aims at preventing capacity hoarding by dominant players at the most, incumbent in the high price market.

In the hybrid approach the SO's (or Regulator's) decision to build infrastructures that do not attract enough demand to cover construction costs in the open season process reflects – abstracting from SoS considerations – the perception by the SO or by the regulator of some flaws in the merchant model. Identifying those flaws is then a crucial element of the decision-making process.

In the rest of this section we discuss methodologies in order to assess the impact on competition of investment increasing the cross-border gas network capacity. Mainstream competition economics and practice provide general guidance on the methodologies in order to assess the competitive impact of gas network investments. We will not survey here those widely studied methodologies.[48] We will focus instead on the consequences of the specific features of the gas industry, including, in particular: i) the extensive use of long term supply contracts necessary to allocate the risks of the investments in production and long-haul transmission; ii) the degree of market power enjoyed by gas producers.

We organize our discussion in two sections . In Section 5.2.1 we discuss the assessment of the competitive impact of the incremental cross-border transmission capacity developed as a part of gas supply deals. In Section 5.2.2 we discuss the assessment of the competitive impact of incremental cross-border transmission capacity developed independently from gas supply deals.

[48] We refer the interested reader, to, for example M. Motta, Competition Policy. Theory and Practice Cambridge University Press (2004).

5.2.1 Assessing the pro-competitive impact of incremental "contracted" transmission capacities

Most of the merchant investments in transmission capacities are part of more complex deals, involving gas supply contracts. Assessing the impact on competition of the network investment is relatively straightforward in that case, as the standard competition policy toolbox can be deployed in order to analyze the importing country's wholesale gas market.[49]

The impact on competition of the additional gas imports depends on the position in the market of the importing firm, that controls the incremental transmission capacity, and on the competitive interaction among the wholesalers active in the market.

The effect of the entry of additional gas in an oligopolistic market is likely to be properly captured by (changes in) the usual concentration indices based on the market shares.[50] One can expect that, in an oligopoly framework, those indices adequately reflect the degree of market power in the industry. The usual assumption is of an inverse relationship between transmission investments and market concentration. In this framework, therefore, competition concerns arise only if the network upgrade (and the corresponding additional imports) increases the degree of concentration in the market. The standard argument based on the relationship between concentration and market power, would in fact be reversed in this case: higher "post-investment" concentration would lead to a prediction of greater exercise of market power. In addition, a reduction of competition could result if the network upgrade involved the use of a scarce resource, like for example the land-use rights that are available in a limited quantity on certain routes. In this case the network investment would have a pre-emptive nature, as it might be difficult to build later additional transmission capacity. We incidentally notice that an effective open-season

[49] We do not separately address the effects of the so called "transit" investments, which allow to transport gas through the country, between an entry and an exit point both located at the borders. The analysis of the competitive impact of those investments is qualitatively identical to that of the other network upgrades.

[50] A concentration index widely used in competition analysis is Herfindal Hirshmann Index (see for example Twomey et al. 2004). Market-shared based indices have foundations in oligopoly theory, in particular when firms compete by setting the volume of their sales (Cournot competition). See for example Energy Journal, Special Issue on Gas markets, 2009.

mechanism, allowing the project to be dimensioned based also on the demand for transmission capacity by parties other than the developers, could mitigate this kind of competition-reducing effects.

As for the strategic interaction among wholesalers, if in the importing country competition follows a "dominant firm-competitive fringe" pattern, variations of the indices based on the market shares might not provide correct indications as to the post-investment market outcome, since the additional gas imports might erode the dominant firm's market shares with no material impacting on gas prices. That would happen if the dominant firm found it profitable to accommodate entry and to continue supporting high prices.

Alternatively, additional gas imports might induce a change in the competitive interaction pattern in the wholesale market. That will happen if the "leader's" market share falls to a level that makes it profitable to move from a high-price/low quantities strategy to a low-price/high quantities strategy. The resulting market outcome depends to a large extent on the competitors' reaction. If concentration in the industry after the network upgrade remains high, the former "followers" may move from a price-taking behaviour to a strategy involving market power exercise. In this case the post-investment interaction pattern in the industry will be imperfectly competitive. If the former "fringe" was very fragmented, the change in the dominant firm's strategy may lead to an outcome close to the (perfect) competition benchmark.

Although predicting the firms' market behaviour is a difficult exercise, analysis on these lines were carried out, for example, in the Italian electricity industry[51]. In particular it should be possible – for an institution having access to the information on the main wholesalers' long term contract positions[52] – to assess:

- The main player's sales reduction in case she accommodates entry, i.e. she keeps supporting the gas price and bears most of the market share erosion caused by the additional imports;

[51] See Indagine conoscitiva sullo stato della liberalizzazione del settore del gas naturale and Indagine conoscitiva sullo stato della liberalizzazione del settore elettrico, Autorità per l'energia elettrica e il gas e Autorità Garante della Concorrenza e del Mercato, 17 June 2004 and 9 February 2005.
[52] Demand predictions on the relevant time horizon clearly play a crucial role in this assessment.

- The main player's profit in the "full displacement" scenario and in alternative scenarios in which market prices reduce and the market-share loss is shared among the largest players;
- The individual incentives for each of the largest competitors to exercise market power in order to mitigate the market price reduction, at the expense of a market share reduction.

A crucial element in predicting the likely reaction by a large incumbent player to additional gas imports in the market is the degree of flexibility of the incumbent's long term contracts. A more aggressive price reaction is to be expected if accommodating the additional imports requires crossing the "take-or-pay" floors that are a common feature of the long-term gas contracts.

Based on the assessment of the likely reaction of the main wholesalers to the additional imports resulting from the network upgrade, it is possible to predict the post-investment market outcome.

5.2.2 Assessing the pro-competitive impact of incremental "non-contracted" transmission capacity

In this section we discuss the assessment of the competitive impact of incremental transmission capacity that is not built in conjunction with a supply contract. We do not expect this situation to be relevant for most merchant projects, as investors in transmission capacity have a strong incentive to lock-in the value of their investment, by underwriting matching purchase and sale long term gas contracts, in order to fill the new transmission capacity. This is typically the case for the projects connecting Europe and the producing countries. Unhedged investments are more likely to be made by SO and by the regulator on behalf of the final customers. We expect that "regulated" investments on the basis of their competition-enhancing properties are likely to be limited to assets increasing transmission capacity within Europe.[53]

Our discussion is then cast in terms of an investment increasing interconnection between two (or more) European price areas. We assume that a relevant setting is one where merchant investments are allowed, irrespective of the methodology governing the SO and the regulator investment decisions (central planning or hybrid model). This leads us to consider a situation in which the SO and the regulator are examining an investment opportunity that market investors do not intend to develop the project as a merchant.

An indicator of the potential for a transmission upgrade to increase competition is the existence of gas price differences among the involved countries. Relatively small price differences, all the more if the sign of difference changes frequently, could not attract market investment in net-positive valued network upgrades if, for example, the spot markets in the involved countries are not liquid enough. In this situation a "regulated" investment can be justified. Its benefits in terms of greater competition would show in the spot market and propagate to longer-term markets (only) to the extent that forward prices reflect spot prices.

If the wholesale price differences among the countries are large and steady, it is particularly important – for the purpose of predicting the competitive effects of the network upgrade – to understand why market investors are not ready to fund that investment on a merchant basis. The reasons as to why the investment is unattractive to market investors might also prevent the competition-enhancing effects of the transmission capacity increase to unfold, in case the investment took place in the "regulated" environment. For example, it could be the case that would-be investors in the network upgrade are not able to procure gas in the low-price country and/or to sell it in the importing country over a time horizon long enough to hedge a large part of the value of the transmission investment. The shortage of gas capacity in the low-price country could for example reflect the exercise of market power by the remote gas producer, which sells gas to importers in both countries. In that case, increasing the interconnection between the countries, might have a limited impact on competition in the wholesale market. It is indeed possible that, as a result of wider interconnection, prices in the two countries converge, but the level they converge to

[53] One possible exception is investments in LNG terminals, because – in principle – they are not

will ultimately be determined by the producer's market power. In other terms, – as long as the investment does not increase competition among the producers – network upgrades could result in wealth transfers between the shippers and the producers, and the customers' welfare will not necessarily increase.

For all those reasons we suggest that investment decisions based on the expectation of a competition enhancing effect of the additional transmission capacity should be based on a thorough assessment of the market conditions.

5.3 Network investments to improve the security of supply

In this section we will discuss a methodology in order to assess the security of supply given the standards introduced by the above mentioned regulation. The starting point of the assessment is to define security targets. In principle the efficient security level is the one corresponding to the equality between the incremental cost and the incremental benefit of providing incremental security[54].

The European Regulation (994/2010) makes this assessment unnecessary to the extent that it sets target level of security. In particular, it requires Member States to respect the N-1 rule and to implement reverse flow on each cross border interconnection. As to supply standards, instead, the Regulation requires that protected customers be ensured gas consumption in the following cases:

- Extreme temperatures during a 7-day peak period occurring with a statistical probability of once in 20 years;
- Any period of at least 30 days of exceptionally high gas demand, occurring with a statistical probability of once in 20 years; and

idiosyncratic. We notice though that recently built LNG terminals in Europe are mostly merchant.

[54] This concept can be translated in the cost of unserved energy, which measures the negative consequences to society of facing gas shortages. The cost is calculated by multiplying Unserved energy (measured by its volume, for instance in mcm); and Value of lost load (euros/mcm). The concept of "value of lost load" refers to the economic value lost if a certain amount of energy is not delivered to a consumer. In other words, it relates to consumers' willingness to pay to avoid interruptions in energy supplies. As such, all the measures necessary to attain the required level of SoS will be performed, unless they are more expensive than the cost of the unserved energy. In this case, the society would be better off without the SoS measure, as its cost is higher than the benefit it generates.

- For a period of at least 30 days in the case of the disruption of the single largest gas infrastructure under average winter conditions.

Finally the Commission states in its Communication, COM(2010) 677/4, on energy infrastructures: "*Every European region should implement infrastructure allowing physical access to at least two different sources*".

For every SO the standards are consequently exogenously given. The only objective left is to thus minimize the expected cost that the system has to bear to meet these standards. This "cost of security" is the sum of a fixed component, represented by the cost of any needed infrastructure (be it a new LNG terminal or a storage site), and a variable component, represented by all the operating costs borne when the disruption takes place.

Given the safety target and the objective function, the SO has to figure out all possible events that might generate a disruption, like for example failure of the main transmission infrastructures, storages or LNG terminals – for the purposes of assessing that the N-1 target is achieved – or interruption of supplies from a certain country– for the purposes of assessing that the dual supplier condition is verified.

The next step is to individuate the possible reactions in order to mitigate the effects of the disruptive event. The preliminary assessment should be performed by taking into account feasible measures given the infrastructural endowment. For instance, a list of such measures is presented in Annex II of the Regulation; these actions are divided according to their nature: demand-side and supply-side; market or non-market based[55]. As for supply-side measures, market-based actions vary from increased production flexibility to increased import and storage use; non-market based measures, instead, consist in the use of strategic storage to the use of stocks of alternative fuels. As for demand-side measures, instead, market based actions include interruptible contracts and voluntary firm load shedding. Non-market based measures, instead, vary from enforced fuel switching to enforced firm load shedding.

[55] We recall that the Regulation requires that priority should be given to market measures.

Given the possible events that might generate a disruption and the countervailing measures at disposal, from the preliminary assessment the SO knows whether the security criteria are met, i.e. whether – given the infrastructure endowment – supply to final customers is prevented by the disruption. Of course, all the measures should be ranked in order of rising unit cost, in order to choose a cost-effective mix to attain the security criteria.

If the standards are not achieved, the SO has to identify the infrastructures and other possible measures needed to attain the required targets in a cost effective way.

If standards are met, then the SO is not required to perform any mandatory investment. On the other hand, the preliminary assessment might show that the cost of meeting the standards in case of disruption might be particularly high; i.e. it might include (costly) non-market measures. In this case, the SO has to promote those infrastructures that, all other things being equal, will reduce most the "cost of security". We will discuss this point with an example. Two new infrastructures, A and B, with identical transportation capacity are under consideration for approval: previous analysis have shown that they will have the same positive impact on welfare (be it because they will increase competition and consequently they will bring about lower prices). Still, they might generate different effects on the security of supply. The SO will test their impact by simulating disruption scenarios taking also into account the presence first of infrastructure A and then of infrastructure B; afterwards, it will compare the outcome with the situation with neither A or B. The impact on SoS of both A and B will thus result from the cost difference in meeting the standards without the new infrastructure and the situation in which A (or B) has been built. The infrastructure that reduces the most the expected cost of the disruption will thus generate higher SoS benefits.

5.3.1 Scenario selection and probability issues

As with every part of the CBA, also this analysis has to do with probability issues related to each disruption scenario: as such, sensitivity analysis is a fundamental moment within security of supply assessment. Moreover, as the Regulation explicitly recalls its rules on risk assessment, the SO, when performing such analysis, should identify the interaction and correlation of risks with other Member States, including interconnections, cross-border supplies, cross-border access to storage facilities and bi-directional capacity. For possible events that might generate security concerns, the SO should study different scenarios, according to the probability of different disruptions and the possibility that some events might jointly occur.

On the action side, the probability related to the expected disruption clearly modifies their NPV. For instance, the operating costs associated to any measure, should be broken down into two components. The fixed operating costs, such as maintenance of pipelines and compressors, would be incurred during the entire life of the infrastructure irrespective of gas supply interruptions. Other operating costs, such as the extra cost of running heating generation plants on fuel oil instead of natural gas, would be incurred only during periods of gas supply disruption. As such, the overall cost of each option will be sensitive to the occurrence of gas crises. Therefore, different scenarios lead to different costs for the same measure; consequently its ranking might change.

5.3.2 SoS within and the three institutional settings

Security of supply standards can be easily declined in the different institutional settings in which investment upgrades are performed. For instance, in a pure merchant framework, the SO or the regulator might subject the permission of building any new infrastructure to some mandatory security of supply standards that the promoter has to implement. In a central planning framework, instead, security of supply is one of the element of the economic analysis performed by the SO whenever considering any new investment: consequently, all other things being equal, the SO will opt for the infrastructure that brings about the highest benefit in terms of security of supply. Finally, in a hybrid framework, the SO, through an open season, tests whether the market is willing to invest in a new infrastructure: in this case, the SO might “purchase” a part of the capacity for security of supply reasons.

6 External Effects

New investments can bring about several external environmental effects. Whenever evaluating any network upgrade it is thus important to attach a monetary value to those effects in order to assess their relative magnitude. These effects can be produced directly by the new transmission facility (e.g. land use, electromagnetic pollution, reduction of visual amenities), or by the changes in the market stemming from the new infrastructure (e.g. increased renewable generation, reduction of losses).

In this chapter we will discuss how to take external costs into account. To do so, first we introduce ExternE[56], a comprehensive methodology to attach a monetary value to external effects; then we present its main results, both for electricity and gas.

6.1 ExternE - NEEDS approach

The methodology aims at attaching a monetary value to all external effects originating from energy related activities. ExternE distinguishes five types of externalities:

- Geographically limited environmental externalities – the release of either substances (e.g. fine particles) or energy (noise, radiation, heat) into the environmental media: air, soil and water;
- Biodiversity loss;
- Climate change externalities – the release of GHG;
- Low probability –high damage risks;
- Insecurity of energy supply.

ExternE refers to the first three types of externalities, even though it has also elaborated a methodology to deal with the fourth one. ExternE results are publicly available and are used by the European Commission (DG Environment) to value external costs. For instance, within the project, a software (EcoSenseWeb) that allows third parties to calculate external costs associated to electricity generation has been developed. The software has a bottom-up approach: one has to specify the main characteristics of the power plant in question and its location. The software, using ExternE methodology, automatically elaborates all the external costs associated to that plant. Let's now discuss each point more in detail.

6.1.1 Local Environmental Externalities

In this subparagraph we will discuss the methodology used to value geographically limited environmental externalities. In order to calculate their damage costs (external costs), one needs to carry out an impact pathway analysis (IPA), tracing the passage of a pollutant from where it is emitted to the affected receptors (population, crops, forests, buildings, etc.). IPA can be divided in four steps:

- Emission: specification of the relevant technologies and pollutants, e.g. kg of oxides of nitrogen (NOx) per GWh emitted by a power plant at a specific site;
- Dispersion: calculation of increased pollutant concentrations in all affected regions, e.g. incremental concentration of ozone, using models of atmospheric dispersion and chemistry for ozone (O3) formation due to NOx;
- Impact: calculation of the cumulated exposure from the increased concentration, followed by calculation of impacts (damage in physical units) from this exposure using an exposure-response function, e.g. cases of asthma due to this increase in O3;
- Cost: valuation of these impacts in monetary terms, e.g. multiplication by the monetary value of a case of asthma.

[56] A project financed by the EU Commission that ended in 2005, which has been later refined by a new European project called NEEDS

It is important to highlight that this methodology attaches a monetary value to this first type of negative externalities insofar it can translate them into health problems (which are the most important negative externalities taken into account), agricultural losses (given by diminishing yields) or damages to buildings and other infrastructures. As such, the environment is just a medium through which pollution reaches a defined receptor, as shown in the chart below.

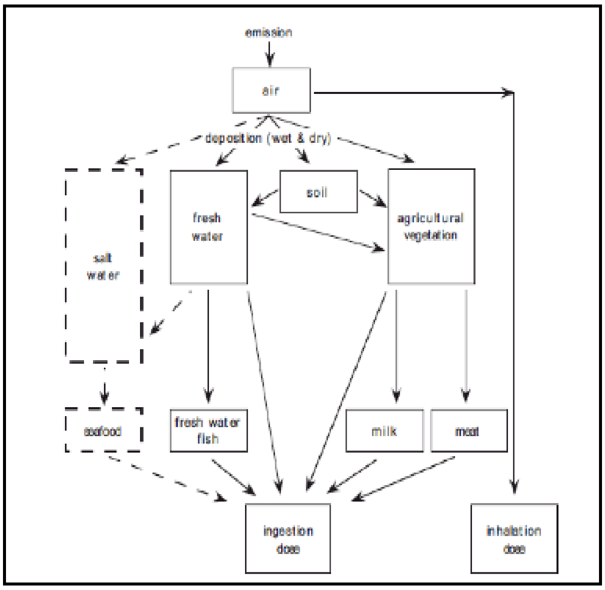

Figure 6.1: impact pathway analysis.
Source: ExternE

It is worth discussing more in detail the last two IPA steps, as they represent the core of the whole methodology. The third step is based on the estimation of different dose-response functions (DRF). Any DRF relates the quantity of a pollutant that affects a recipient (e.g. population) to the physical impact on this recipient (e.g. incremental number of hospitalizations). In the narrow sense of the term, it should be based on the dose actually absorbed by a recipient. However, the term DRF is often used in a wider sense where it is formulated directly in terms of the concentration of a pollutant in the environment, accounting implicitly for the absorption of the pollutant from the environmental medium into the body. There exists an immense literature of epidemiological and medical studies that are the basis for the definition of such functions. As such, DRF is a central ingredient in the IPA, as a damage can be quantified only if the corresponding DRF is known. Such functions are available for the impacts on human health, building materials and crops, caused by a range of pollutants. To this respect, the most comprehensive reference for health impacts is the IRIS database of the US EPA (http://country.epa.gov/iriswebp/iris/index.html).

ExternE recognizes several difficulties in calculating DRFs. First of all, the health impacts are small at typical concentrations: as such, it is difficult for epidemiologists to measure the impacts. Secondly, in contrast to the extreme complexity of the underlying biological processes, epidemiological studies can take into account only certain simple gross features, for example the variation of respiratory hospital admissions as a function of the SO2 concentration to which the study population is exposed. Thirdly, populations are exposed to a mix of different pollutants that tend to be highly correlated with each other. Therefore, it is difficult to establish definite links between an end-point and a particular pollutant.

Bearing in mind the above mentioned *caveat*, it is possible to relate an exposure increase of various effects, to a particular pollutant, such as: increased mortality, increased hospitalization, reduction of working days, etc. For instance, ExternE has elaborated ozone-related DRFs: mortality risk increases by 0.3% per 10 μg/m3 increase in the daily exposure to ozone; consultations for allergic rhinitis increase by 1.60 consultations per 1000 adults aged 15-64 per 10 μg/m3 ozone increase.

The fourth and final step attaches a monetary value to those effects. ExternE applies different methodologies according to the effect that is under consideration. First, mortality is valued with a WTP approach, as described in chapter 2. Questionnaires were handed out in some European countries to value the willingness to pay for reducing their mortality risk over the next 10 years. This has led to the elaboration of an index named VOLY (value of a life year), which basically tells how much people value one more year of life. The value was approximated to 45,000 euro[57].

Secondly, morbidity is valued by summing health service costs, opportunity costs (either work time loss or leisure time loss) and disutility deriving from either actually suffering from a disease or by the anxiety generated by a polluted environment. The

[57] 2005 value.

first two components can be approximated using market prices that exist for those items. On the other hand, loss of utility has been derived through WTP approach.

Finally, damages on agriculture and buildings were value either with market prices (agricultural products) or with restoration costs (buildings and cultural sites).

Once the effects of each pollutant considered have been estimated and monetized, it is then possible to allocate these costs to each polluting technology. To this respect, the methodological framework used is Life Cycle Assessment (LCA). NEEDS has developed a dynamic LCA, which takes into account also LCA of future technologies. This has been done by combining prospective methods that are used to reflect technological change (like technology foresight and experience Curves) with the traditional LCA approach. In contrast to traditional static LCA, in fact, a direct link between LCA tools and energy system modelling has been established, thus enabling direct feedback loops between future energy system configurations and the life cycle inventories of individual energy technologies.

The LCA results in the inventory of all the pollutants emitted by the technology under consideration throughout its life for a standard utilization rate. This allows to express a unitary value (e.g. kg SO2-emissions per kWh) and then to combine it with external costs per unit (e.g. €/kg SO2-emissions), to finally quantify external costs per kWh for each reference technology.

The problem with Dynamic LCA is that it can result in double counting the value of renewable generation. For instance, in many member states RES already receive a subsidy; in this case, taking into account their associated external benefit when assessing the feasibility of a line would result in double counting the positive externality of RES.

6.1.2 Biodiversity Loss

The main limit of the above mentioned approach is that it does not take into account an environmental damage if it has no effect on human health or on economic activities. Still, one might argue that ecosystems have an intrinsic value, with the consequence that any damage has to be accounted for. To value this, NEEDS has introduced a new methodology based on the restoration cost approach. This approach measures the costs of restoring a modified ecosystem. The underlying assumption is that the cost of replacing an ecosystem is an estimate of its value.

In order to quantify the damage suffered by the involved ecosystem, NEEDS has elaborated the concept of biodiversity loss. Biodiversity is measured by species richness, i.e. the number of species living in a certain area. Damages to ecosystem quality are expressed as the percentage of species that are threatened or that have disappeared in a certain area during a certain time due to the environmental impact.

There are two main actions that can bring about biodiversity losses, namely airborne emissions and land use changes due to energy production and infrastructures. To quantify the loss, defined as the Potentially Disappeared Fraction (PDF), one has to compute the relative difference between the number of species on the reference conditions and the number of species after the above mentioned effects occur. A monetary value is then attached by calculating the restoration costs of either changing back the land use or of removing the pollutants. The following figure shows the underlying logic applied by NEEDS to value biodiversity losses.

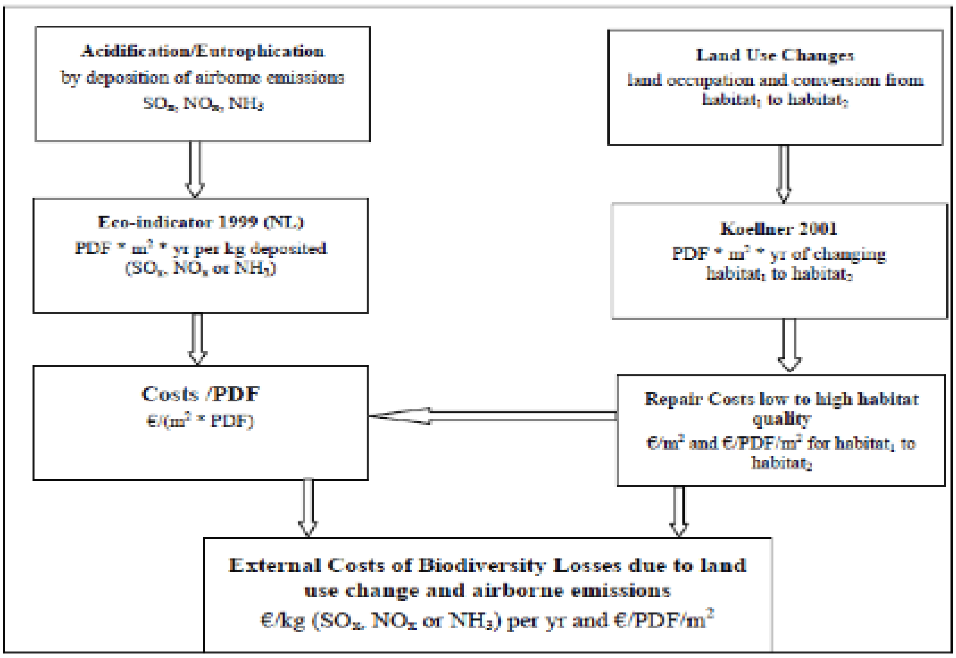

Figure 6.2: Biodiversity loss calculation.

Source: NEEDS.

The following table presents the restoration costs per square meter for biodiversity losses due to land-use changes from built up land into different target biotopes for Germany and EU 25, as calculated by NEEDS.

Restoration Costs for Different Target Biotopes - Germany & EU 25 2004 Starting Biotope: Built Up Land [€ per m^2]			
Land Use Category	CORINE Classification Number	Restoration Costs [€ per m^2]	
		Germany	EU 25
Integrated Arable	2112	0.18	0.17
Organic Arable	2113	0.46	0.42
Organic Orchards	2222	4.41	4.06
Intensive Pasture and Meadows	2311	0.37	0.34
Less intensive Pasture and Meadows	2312	0.83	0.76
Organic Pasture and Meadows	2313	2.06	1.90
Broad-leafed Forest	311	2.89	2.66
Plantation Forest	312	2.89	2.66
Forest Edge	314	9.12	8.39
Country Average		1.17	1.52

Table 6.1: Restoration costs for different land uses.

Source: NEEDS.

6.1.3 CO2 Emissions

TO value the impact of CO2 emissions, ExternE elaborated a methodology based on the concept of damage cost. In practice, they estimated the damages and related costs caused by an increase in global temperature, until 2300. At present, though, not only are there different studies and guidelines that provide reference values to be used for CBA, but, at least in Europe, there is an active carbon market, on which it is possible to observe not only spot prices but also forward prices. Depending on the source one wants to rely on, figures range from 20 €/ton estimate for the CO_2 permit trading price, to higher values estimated in the scientific literature (the Stern Review[58] suggested an average damage value of €75/ton CO_2). The use of this value depends on the assumed time horizon of the project under analysis.

[58] 'The Economics of Climate Change', country.sternreview.org.uk, 2006.

6.1.4 Low Probability – High Risk

Another type of externality is generated by the consequences of major accidents. These events are known as low probability – high risk scenarios. Generally, these events generate consistent damages and, as such, are very costly. There are two main concerns whenever evaluating this type of externality, namely: the possibility of calculating the probability that the event will occur and the associated costs. The difficulty is exacerbated by the fact that different accidents (with different associated costs) can happen with different probability: as such, the calculation of the expected cost is quite a challenge.

To partially overcome these issues, ExternE has used ENSAD (Energy-related Severe Accident Database), a comprehensive database on severe accidents with an emphasis on the energy sector, established by the Paul Scherrer Institute (PSI). The database allows to carry out comprehensive analysis of accident risks, that are not limited to power plants but cover full energy chains, including exploration, extraction, processing, storage, transmission and waste management. Just to give an example, in the figure below, we show the comparison of frequency-consequence curves for full energy chains in OECD countries for the period 1969-2000. The curves for coal, oil, natural gas, liquefied petroleum gas (LPG) and hydro are based on historical accidents and show immediate fatalities. For the nuclear chain, the results originate from the plant-specific Probabilistic Safety Assessment (PSA) for the Swiss nuclear power plant Muehleberg and reflect latent fatalities.

Thanks to the database, it is possible to estimate the probability of any accident and its associated cost (which is derived from actual incurred costs in past accidents). Once the probability is known, it is possible to apply standard IPA. For instance, in its reference scenario for a core melt accident followed by a release of 1 % of the core, ExternE calculated that external costs are in the range of €cent 0.0005/kWh. Since external costs associated to major accidents resulted negligible for all technologies, they were not included in the final assessment.

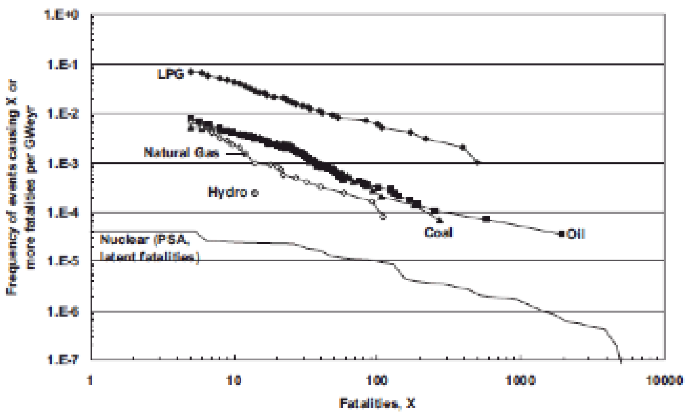

Figure 6.3: Frequency of accidents and related fatalities for different technologies.

Source: ExternE.

6.2 Applications

It is now time to present and discuss some major results. First we show ExternE – Needs external costs data on electricity transmission networks. Then we will present electricity generation external costs and how they can be used to value the impact of renewable generation. The data presented here helps to indentify the order of magnitude of external costs, compared to the overall investment costs. We will finally analyze gas associated externalities.

6.2.1 Transmission lines in the electricity sector

In this section, we will introduce the main results concerning external costs for electricity transmission[59]. As for electricity transmission lines, the main sources of externalities studied were land use and electromagnetic pollution. Moreover, NEEDS also took visual effects into account. With respect to the last issue, a seminal paper by Atkinson *et al.* (2004) provided a first important assessment. The authors conducted a contingent valuation survey to assess the size of the visual amenity conferred on local landscapes by replacing the overhead electricity transmission towers with those of alternative designs. Survey respondents were asked to rank six tower designs. Respondents who ranked any new design as being preferable to the current one were asked to express their WTP to see specified towers in their area changed to this new design. The main features of that result was that the least

[59] Published in 2009.

favoured of the six designs generated a negative WTP whilst the most favoured design generated a mean WTP of €10 per household. Building on this experience, NEEDS, through the use of specific surveys, estimated a reduction in house value given by the visual disutility of having external wires close to the building. The results of the study are shown in the table below.

Impact Categories	**External Costs (k€/ km)**	
	Average	**Max (urban area)**
Visual intrusion	40	11,000
Electromagnetic fields	9	416
Emission due to material construction	7.8	7.8
Biodiversity loss and land use	7.4	7.4
TOTAL	**64**	**11,431**

Table 6.2: External costs for electricity transmission lines.

Source: NEEDS.

From the table above it is possible to see that external costs for transmission lines are in general negligible, and they should not change the economics of a new investment. This might not hold only in particular cases, for instance when the facility is built near sensible urban areas.

6.2.2 Reduction of the conventional generators negative externalities

A new transmission facility can bring about dramatic changes in the generation portfolio and this can have significant environmental effects which should be taken into account whenever performing a CBA analysis. Generally, these effects far outweigh those created directly by the construction of the facility itself. For instance, increased renewable generation reduces electricity production from conventional sources. This reduction brings about positive environmental effects, ranging from local ones to global ones, depending on the characteristics of the pollutants that are no longer emitted. Just to provide a practical example, we present here external costs associated to electricity generation in Germany.

This estimate considers current technologies and CO2 avoidance cost of 19€ per ton. Again, it is important to highlight that these costs are shown mainly to give the order of magnitude of external costs compared to generation costs.

Quantified Marginal External Costs of Electricity Production in Germany (€cent/kWh)						
	Coal	**Lignite**	**Gas**	**Nuclear**	**Wind**	**Hydro**
Damage cost						
Noise	0	0	0	0	0.005	0
Health	0.73	0.99	0.34	0.17	0.072	0.051
Material	0.015	0.02	0.007	0.002	0.002	0.001
Crops	0	0	0	0.0008	0.0007	0.0002
sub-TOTAL	0.75	1.01	0.35	0.17	0.08	0.05
Avoidance Cost						
Ecosystems	0.2	0.78	0.04	0.05	0.04	0.03
Global Warming	1.60	2.00	0.73	0.03	0.04	0.03

Table 6.3: External costs for electricity generation.

Source: ExternE (2004).

6.2.3 Gas sector applications

While the external costs for electricity generation have been widely studied, less is known about the impact of the natural gas production chain on the environment.

The only study we are aware of was carried out within the already mentioned Needs project, which gives some estimates of gas environmental costs. We report here its main indicators and conclusions – stressing that, to date, the robustness of these results cannot be corroborated by alternative approaches due to the lack of data availability.

Within the Needs project, the report “Burdens, Impacts And Externalities From Natural Gas Chain” calculates the external cost deriving from different pollutants (NOx, SO2, volatile organic compounds, greenhouse gasses) per unit of gas produced or transported. As such, no estimation has been made on either land use or on the possible visual impact of gas pipeline and compression stations.

In particular, the value of externalities per unit of emissions in gas extraction and transportation have been taken from the three main exporting countries: Norway, Algeria and Russia. The study has also elaborated different production and transportation scenarios, up till 2030, to see how enhanced consumption and technical improvements might impact external costs. Here we will just present the results for 2010, which are based on real data. First, we report the results for GHG externalities costs due to gas production below (in Euros per ton of pollutant).

	Norway	Algeria	Russia
	2010		
CO_2	2.19E-02	2.16E-02	2.33E-02
CH_4	4.37E-04	1.86E-04	1.95E-04
N_2O	7.31E-03	4.12E-03	4.21E-03

Table 6.4. Unit external costs (euro per ton) of GHG emissions from natural gas production offshore (Norway) and onshore (Algeria and Russia) in 2010.

Source: NEEDS.

Then, we show the external costs related to gas transportation. In this respect, the study takes into account only Russian pipelines. Unit External Costs [Euro per Ton] for NMVOC and GHG-emissions from transport of natural gas, considering long distance Russian pipelines, are as follows:

	2010
CO2	9.67E-10
CH4	6.47E-04
N2O	0
NMVOCN2O	7.22E-07

Table 6.5. Unit external costs, gas transportation

Source: Needs.

Here we must highlight that Russian pipeline standards are far from European standards in terms of gas losses. Summing up production and transportation externalities, the overall external cost associated to natural gas is estimated at 1.8 euro per ton. As such, it can be considered negligible.

6.3 Practical considerations

Major investments can generate significant external costs: it is thus important to assess them, in order to attach a proper value to the proposed facility. Estimation of external costs can be quite a challenge, in particular if one cannot rely on previous studies or trusted methodologies. As a consequence, external costs can be a source of major concern whenever performing risk assessment and sensitivity analysis prior to deciding whether to realize the investment. The object of ExternE is to overcome these challenges by giving a shared tool to value external costs. As specified above, its result are commonly used by the EU Commission.

As for external effects given by a generation portfolio change, ExternE results can be easily applied to the results generated by the SCODM. In particular, as the optimal dispatch model already quantifies changes in CO2 emissions, there is just the need to multiply that number by the estimated CO2 cost in order to compute the external effects on climate change generated by the new transmission facility. As for the local impact and biodiversity losses, given that the model quantifies the relative changes in power output for each productive unit, one has to just multiply those differences by each technology specific unit external cost in order to value the external effects.

On the other hand, we have seen that external costs stemming from the new facility itself (be it an electricity line or a gas pipeline) are generally negligible. In this respect, even if ExternE has elaborated reference values, ad hoc studies, for instance with specific surveys, might offer a better solution.

7 Sharing the cost of cross-border transmission investments

In this chapter we will address the issues arising when an investment on the electricity transmission or the gas transportation network affects several countries, or more generally several geographic areas where different authorities regulate tariffs and are responsible for investment decisions. In the highly meshed central European gas and electricity systems, not only "cross-border" infrastructures, but also major investments inside one country may have a material impact on the neighboring countries' markets. In the following sections we will discuss how to split the cost of network upgrades increasing cross-border capacity among the involved countries, based on the benefits accruing to each country's generators and customers as a consequence of the changes in the prices of electricity (or gas). We will briefly discuss in section 7.1.1 how benefits (and costs) of a different nature fit into the framework developed in this chapter.

The chapter is organized in 3 sections. In section 1 we highlight that network investments may cause, besides a total net surplus increase, large wealth transfers among stakeholders or countries. In this context cost-sharing is an aspect – and perhaps not the most relevant – of the broader question on whether some wealth redistribution effects of the network expansion should be sterilized through appropriate policy measures. Once that (political) question is answered, a cost-sharing rule based on the benefit obtained by each country or stakeholder appears natural and its implementation is relatively straightforward. In section 2 we survey the US experience on cost-allocation of network investments among network users at different locations. In section 3 we summarize the policy implications of our analysis.

7.1 Benefit-based cost sharing network investments

The main methodological problem in a benefit-based approach to cost sharing is that the benefit of the network upgrade to each party depends on each stakeholder's net energy position. In Chapter 3 we carried out our analysis based on the assumptions that market participants were not hedged, so that all trades would take place on the spot basis. Here we refer to this setting as “no hedge” and consider the other extreme situation, that we call the “full-hedge”.

In the full-hedge setting all the market participants buy and sell power via long term contracts. A high propensity to hedge can be expected in markets where transmission investment is mostly merchant (see section 7.2). In that case, the party investing in network assets becomes the owner of a set of transmission rights corresponding to the additional transmission capacity created by the investment, as assessed by the system operator. In this environment it is likely that the investor will seek to hedge the value of the transmission rights by taking the appropriate positions on the energy markets. For example, if the investment results in additional transmission capacity from country A to country B, the investor might secure the value of that capacity by purchasing electricity futures in country A and selling electricity futures in country B. These positions, taken at the same time as the investor commits to the network upgrade, allow the investor to appropriate the net surplus created by the investment, as long as the electricity purchases and sales take place at pre-investment prices, reflecting the level of existing transmission capacity prior to the investment.

We will now illustrate this through a simple example. Figure 4.1.1 below shows the equilibrium of the wholesale electricity market in the two countries before and after an investment expanding interconnection capacity. All our results carry out to more complex settings, where, for example, demand is price-elastic, more than two countries are involved or the investment takes place entirely within one country’s network.

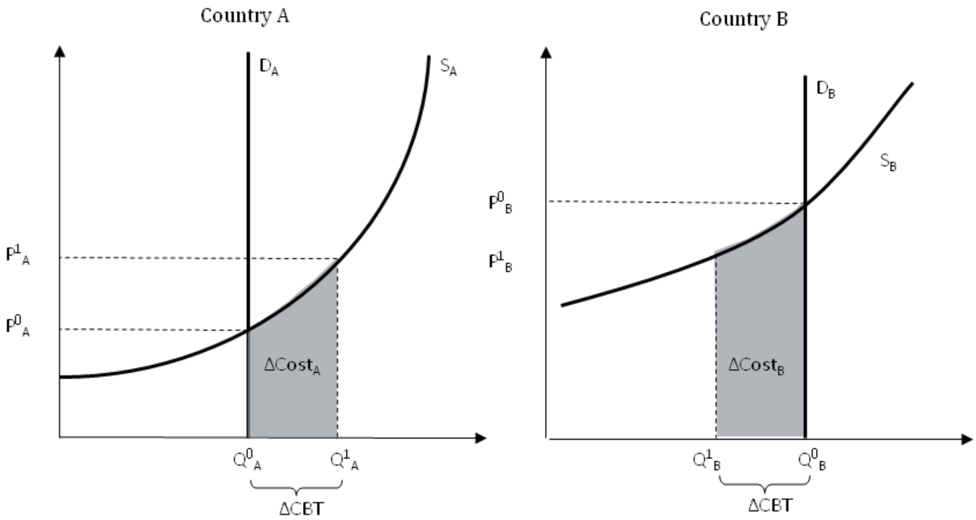

Figure 7.1: The impact of the network expansion on participating countries.

(P_A^0, Q_A^0) and (P_B^0, Q_B^0) represent the electricity spot market equilibrium before the network upgrade, in country A and B respectively. For simplicity demand in A, D_A is taken to include pre-investment exports from A to B and D_B is the demand in B net of the pre-investment imports.

The investment increases interconnection capacity between the two countries by ΔCBT; the new market equilibrium is represented by points (P_A^1, Q_A^1) and (P_B^1, Q_B^1). For later reference we call $\Delta Cost_A$ the generation cost increase caused in A by the production of additional ΔCBT MW exported to B; $\Delta Cost_B$ is the cost saved by the generators in B displaced by the additional imports.

As a result of the increased interconnection capacity, equilibrium exports from country A to country B increase, so that:

- The electricity spot price in A, the exporting country, increases;
- The electricity spot price in B, the importing country, decreases.

In this setting all the generators and loads producing and consuming before the transmission upgrade are assumed to have locked-in their positions. For example, one could assume that:

- All consumers in country A have signed long term supply contracts with generators in A at the pre-investment price P_A^0;
- Some generators in A have purchased long-term rights to use the existing cross border capacity, at a price reflecting the market conditions prevailing before the investment $(P_B^0 - P_A^0)$
- Consumers in B have signed long term supply contracts, at the price prevailing before the investment P_B^0, with the more efficient generators in B and with the generators in A that own the transmission rights,

How the benefits of the transmission upgrade are shared among the stakeholders depends on the institutional setting. Consider first a merchant setting (see Figure 4.1.2). Generators in A with variable costs between P_A^0 and P_A^1 would negotiate with generators in B with variable costs between P_B^1 and P_B^0, recognizing that increasing the transmission capacity has positive value for both. They will find a way to share the investment cost and the value of the additional transmission capacity, shown in the figure as CR. The total incremental surplus created by the investment, though, goes beyond CR, since each party will also obtain greater surplus from producing electricity (generators in A) and from selling electricity (generators in B).

Thanks to the incremental transmission capacity between A and B, the marginal ΔCBT MW of generators in B will replace their more expensive production (saving $\Delta Cost_B$) with spot market purchases (at price P_A^1) while still supplying that power to final customers, under the long term contracts, at the pre-investment price P_B^0 . That will result in incremental profits shown in the figure as NS_A.

Some generators in A, that did not produce before the investment, will produce additional ΔCBT MW and sell them at the new price in zone A, collecting $P_A^1 * \Delta CBT - \Delta Cost_A$ profits, shown as NS_B in the figure .

In this setting consumers do not benefit from the increased interconnection capacity in the short run, since demand is inelastic (no incremental surplus from additional consumption is created) and they are totally hedged (no infra-marginal rent transfer takes place as a consequence of the price change).

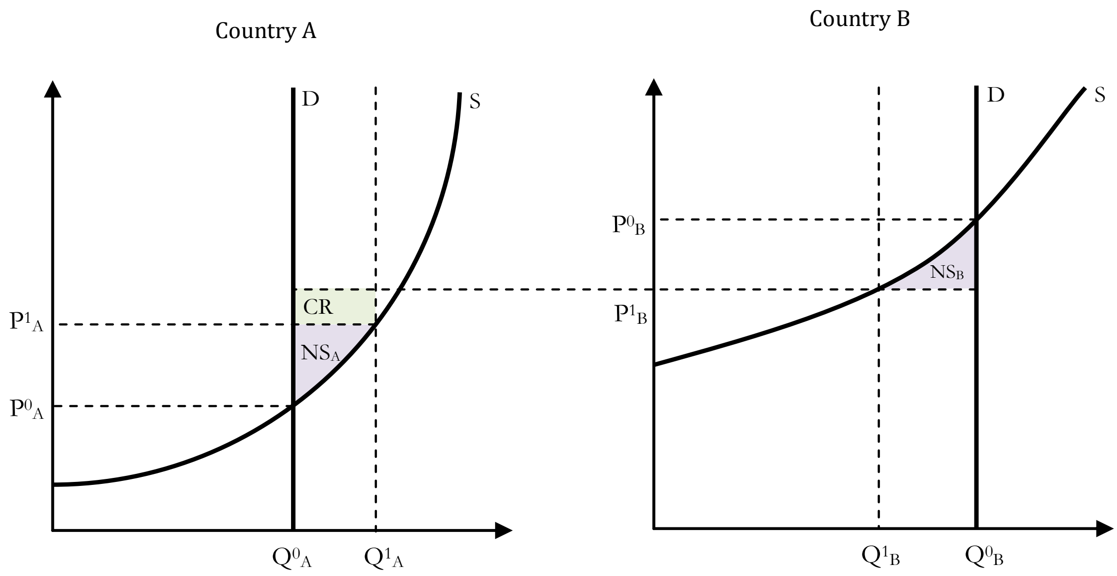

Figure 7.2: The impact of the network expansion on participating countries, the merchant setting.

CR is the congestion rent, where $CR = (P_B^1 - P_A^1)(Q_A^1 - Q_A^0)$. NS_A is a profit of country A from additional production, where $NS_A = (P_A^1 - Cost_A)(Q_A^1 - Q_A^0)$. NS_B is an incremental profit of country B, where $NS_B = (Cost_B - P_B^1)(Q_B^0 - Q_B^1)$.

Therefore, in principle, any split of $CR + NS_A - NS_B$[60] could result as the outcome of the negotiation between generators in A and generators in B for the construction of the new line. In a static short-run context like the one we are considering here, the economic theory does not provide indications as to the sharing of $CR + NS_A - NS_B$. In a longer term context, though, where for example the decision to build generation capacity is endogenous, competition would lead to an outcome where the portion NS_A of the rent is collected by the generators in A, NS_B by the generators in B. In this case only the CR's split results from the negotiation between the generators.

In an alternative setting the investment decision is taken by SO on behalf of the (still fully hedged) customers. In this case the CR portion of the benefit will go to the customers, through the SO, whereas the $NS_A - NS_B$ part will go to the generators.

In conclusion, in a fully hedged environment none of the stakeholders would suffer a welfare loss because of the investment. This is due to the fact that there would be no infra-marginal surplus transfer, as the values of all of the pre-existing positions are fixed. As a consequence, each party would be either indifferent or better off after the investment.

Who appropriates the incremental surplus generated by the investment depends on the hedging structure, the size of each market, the slope of the demand and supply curves in the different areas and who collects the congestion rents.

We notice, incidentally, that the "full-hedge" scenario is not just a theoretical exercise. Consider for example the case of a large exporting country, like France, whose cost function becomes relatively steep as export increases due to the large nuclear fleet. In that case, the expansion of export capacity can create a large surplus transfer from customers to generators located in France as the production increases, due to greater export opportunities, determines a large price increase. One element of the new design of the French electricity market (the NOME, as Nouvelle Organization du Marché Electrique) can be considered as addressing the effects of this feature in the French market. In ultra-simplified terms, each final customer in France would be allocated the equivalent of a fixed-price supply contract, with a price equal to the unit cost of the French nuclear production. Considering the share of their consumption covered by these contracts, the French consumers' surplus will then be independent of electricity market prices. That would prevent any infra-marginal surplus reallocation (from the French customers to the French generators) in case wholesale

[60] Provided the cost of the line is shared in a way that leaves a positive net surplus to each party.

prices in France increased, for example because of the expansion of the cross-border interconnection capacity.[61] Policies on that line appear to be justifiable on fairness grounds, to the extent that it would not alter the surplus distribution among countries resulting from investments and policy decisions taken in the pre-liberalization framework, in a national perspective. On the other hand it is not clear that all European countries are in the position to implement a policy on this line, because of the different legal frameworks and, above all, ownership structure of the electricity companies.

Next, we turn to the analysis of the situation where the market is not hedged. Consider in particular the setting in which the SO takes the investment decision and collects the congestion rents, on behalf of the consumers.

In a “non-hedged” market, the increase of transmission capacity between A and B causes infra-marginal and marginal effects. The infra-marginal effects are the changes in the economic value of the transactions that would take place in the absence of the network upgrade. The net sum, across all market participants, of the infra-marginal effects is zero; in other terms they are mere wealth transfers. Marginal effects correspond to changes in produced and consumed quantities after the investment. The total net surplus of the investment, $(\Delta Cost_B - \Delta Cost_A)$, is the sum of all the marginal effects resulting from the network upgrade. The following Table reports the marginal and infra-marginal effects of the network upgrade.

Stakeholder	Infra-marginal welfare effect	Marginal welfare effect
Consumers in A	$-(P_A^1 - P_A^0) * Q_A$	0
Consumers in B	$-(P_B^1 - P_B^0) * Q_B$	0
Generators in A	$(P_A^1 - P_A^0) * Q_A$	$P_A^1 * \Delta CBT - \Delta Cost_A$
Generators in B	$(P_B^1 - P_B^0) * (Q_B - \Delta CBT)$	$-P_B^0 * \Delta CBT + \Delta Cost_B$
Congestion rent	$CBT_0 * ((P_A^1 - P_A^0) - (P_B^1 - P_B^0))$	$(P_A^1 - P_B^1) * \Delta CBT$

Table 7.1: Infra-marginal and the marginal welfare effects of the network expansion

61 The same result was obtained, according to some commentators, when ordinary customers were supplied at regulated tariffs, by setting those tariffs at a level which is inconsistent with the prevailing wholesale market prices.

Consumers in A are negatively affected by the network upgrade, since the electricity price in A increases because of the increased exports and, being non-hedged they are exposed to the higher price. Consumers in B are in the opposite situation.

Generators in A benefit from both the infra-marginal and the marginal effect of the network upgrade. The quantity they have produced before the investment is sold at a higher price after the investment and additional margins are collected on the incremental quantities. Generators in B are in the opposite situation.

The sign of change in the congestion rent – that we assume to be split in some proportion between consumers in A and in B – is undetermined. On the one hand the additional flows between A and B, made possible by the investment, create an incremental congestions rent; on the other hand the value of the pre-existing transmission capacity reduces, as the price differential between the two zones shrinks.

We notice incidentally that, in a non-hedged market, the wealth-transfer effects may be substantial, potentially far greater than the cost of the network investments. That could lead some countries to oppose positive-net valued investments that increase domestic electricity prices.[62] Against the opposition to welfare enhancing projects by the "losing" stakeholders (or countries) one could oppose the goals commonly attached to the creation of a single market for electricity: delivering to all European customers the benefits of a larger and more competitive market. It remains to be seen how compelling this argument would be in practice, in particular if no policy tools (other than the electricity prices) are available to a Member State to pass on the value of some scarce resource to its citizens, like a large hydraulic endowment, or to compensate its citizens for bearing costs that are not fully internalized, like the risk of nuclear accidents. A further possible argument is that stakeholders that would lose from the investment can mitigate the impact of the post-investment market conditions by hedging their positions on a voluntary basis. In fact this might not be possible, for example because sufficiently long-term products might not be

[62] That would happen, in particular, if measures that freeze the pre-investment surplus allocation (see our discussion of the French NOME program above) were not available.

traded. Furthermore, by the time the information on the investment's impact motivates "losing" stakeholders to seek hedging, long-term prices would most likely already reflect the post-investment market conditions.

Going back to the cost allocation issue, our example shows that in a non-hedged market generators located in exporting areas and customers located in importing areas benefit from the transmission upgrade. In addition, congestion rent changes affect customers located in both areas, depending on the sharing agreement. To our knowledge, only in some US markets attempts were made to allocate the cost of the network investment based on the expected benefits (see next section). In all cases though, the cost of the investment is allocated to customers only. In particular, the investment cost is allocated to customers located in areas where prices are expected to drop after the network upgrade.

We were not able to find statements by the US SOs and Regulators on the rationale for this approach. We conjecture that the decision to not allocate any cost on the generators located in the exporting areas may be based on the following motivations: First, the design of the transmission tariffs may result in a translation to the exporting area's customers of charges formally assessed to the generators. In particular, if the transmission tariff adds to the generators variable costs (i.e. it is assessed on a per MWh basis), in a competitive generation market (and/or in case demand is highly inelastic) a tariff increase will be entirely reflected in the wholesale electricity price. If this is the case, the objective of allocating part of the investment costs to the generators' would not be achieved. Furthermore, the energy price in the exporting area will rise and the congestion rents will be reduced. Therefore, customers located in the exporting area will bear a greater welfare loss than if the entire cost of the network upgrade was allocated to the customers in the importing area. This argument ceases to hold if non distorted transmission tariffs can be implemented. [63]

A second possible rationale for not placing transmission investment cost on the generators is the assumption that competition will – in time – wipe-out any additional rents accruing to the generators as a consequence of the transmission upgrade. The idea can be illustrated in our simple example, where we assume that, before the network upgrade, a long-run equilibrium had been reached in area A. By "long-run equilibrium" we mean that the total generation cost in A is minimized, given the pre-investment level of interconnection, and generators in A obtain a level of profits that do not encourage leaving the industry, nor attract further entry. After the investment, then, generators in A collect a higher-than-normal profit; this attracts entry in the industry and – under the assumption that the technology that was marginal before the network upgrade can be replicated – prices in A will move back to pre-investment levels. Generators will collect normal profits again and the only lasting effect of network upgrade will be:

- A price reduction in area B; and/or
- An increase in the congestion rent.

This long-term perspective could provide a basis for splitting the network's upgrade costs based (only) on the change in the consumer's surplus, and for using congestion rents to pay for transmission costs.

The fairness of that approach, though, could be questioned if the installed capacity adjustments, that would transfer the benefits created by the network upgrade to the customers, might take a long time and massive welfare transfers might have to take place before the system settles to a new long-run equilibrium.

In a well functioning decentralized decision making environment the cost of the network upgrade is borne by the party enjoying the benefits, typically in the form of transportation rights. Then, no public decision-making on cost-sharing is necessary, being the investment national or multinational. The merchant approach implemented in the US gas market appears to meet this characterization (see next section)

As we discussed in Chapter 5 the European approach, as it stands now, is characterized by a more centralized decision making. Furthermore, the open season mechanism departs from an ideal decentralized process, notably in the way the

[63] Tariffs assessed on a different basis (e.g. on a per MW-year basis) will be transferred to customers only in the long run, when they will impact on the entry decisions of new generators. Therefore they are suitable to extract the generator's rent in the short-run.

costs of the new capacity allocated to the subscribers are assessed (generally involving some averaging of the total network costs) and in the length of the commitments that the subscribers are asked to take (sometimes shorter than the assets' economic life).

In this respect, any evolution of the European approach towards a more accurate allocation of each network upgrade cost to the parties committing to purchase the corresponding incremental transportation capacity would bring the system closer to an ideal decentralized approach and reduce the cost-allocation issues.

This is more important in the gas than in the electricity industry, since in the gas industry assessing how each class of stakeholders is affected by the network upgrade is made difficult by the complex (and non transparent) risk-sharing architecture. Very long term electricity contracts are extremely rare and one could safely assume the "no hedge" scenario discussed above is the one relevant for the purpose of assessing the benefits (and losses) of each class of stakeholders.

On the contrary a significant part of the gas supplied to Europe is procured at the wholesale level under long-term agreements and renegotiation clauses are a way (albeit imperfect) of reallocating between buyers and sellers the risk of changes in the gas market value. One could therefore expect that gas producers would bear part of the consequences of the changes in gas prices in Europe resulting from greater market integration. For example, if prices in one country fell as a consequence of competition-increasing network investments, the suppliers enjoying high pre-investment prices will call for a renegotiation of their upstream contracts and (try to) share the effects of the price reduction with gas producers. That makes it all but obvious as to who ultimately benefits or loses due to the network upgrade.

7.1.1 Benefits and costs that are not reflected in electricity and gas prices.

In the previous paragraphs we have discussed how to split the cost of network upgrades increasing cross-border capacity among the involved countries, based on the benefits accruing to each country's generators and customers as a consequence of the changes in the prices of electricity (or gas).

Our results appear to extend to benefits and costs that are not directly reflected in electricity (and gas) prices. Consider for example the environmental cost borne by the population of the country that will increase electricity exports thanks to the network upgrade; in particular consider a cost that is not already internalized in any emission charge and, therefore, reflected in the electricity prices. That could be the case, for example, of small particles emissions by coal firing generators.

The methodology developed in Chapter 6 allows assessing the monetary value of those costs, as we showed in the context of the assessment of the social value of the upgrade. As a consequence, it is possible to net out that estimated monetary cost from the benefits accruing to the exporting country's stakeholders, for the purpose of calculating their share of the investment's cost. It could be argued, though, that since the exporting country would not charge the generators for that externality in case production increased for reasons unrelated to the transmission upgrade, for example as a consequence of the retirement of some generation capacity located within country, considering that cost when it comes to sharing the investment cost across Countries is unfair.

A further area of benefits that we have not included in the cost-sharing framework developed in the previous sections is security of supply. The approach developed in Chapter 4 allows assessing the economic value of a network upgrade in terms of security of supply, in terms of lower expected value of the electricity non-supplied. Therefore that benefit too can be included among the benefits generated in each country by the cross-border investment, for the purpose of sharing the cost. In that respect a possibly contentious issue is the value attributed to security, as different Countries appear show different preferences, at least in terms of Value of the Lost Load. In this respect a coordinated approach, among the system operators, to assessing system security and to setting the security targets is a pre-requisite to reaching an agreement on the value of cross-border network upgrades in term of additional security in each of the involved Countries.

7.2 Cost allocating methodologies in the US

In the US cost allocation for new transportation has become a debated policy issue in the last few years, in particular in the electricity industry. Before the deregulation process, transmission lines were built in the US primarily by investor-owned utilities, vertically integrated in generation and supply, and subject to traditional cost of service regulation. External effects on other networks would be relatively unimportant, as each utility would develop a network functional to serve its own load, and interconnections had mainly a security/reliability role.

Cost allocation issues have become relevant following the Energy Policy Act of 1992, which introduced competition in generation service. FERC issued Orders 888 and 889, establishing an open access regulatory regime for the transmission grid. The economic and operational links between utilities and transmission were further weakened by the advent of regional transmission organizations (RTOs) in the 1990s and during the 21st Century, in the Northeast, Midwest, Texas, and California[64]. In RTO markets, utilities retain ownership of the transmission grid but operational control is exercised by the RTO.

In this section, we will first review the merchant approach to gas transportation investments in the US, where the investors in new gas infrastructures bear the cost and own the transportation rights that investment creates. Then we will review some recent developments related to transmission cost-allocation in the US electricity markets.

7.2.1 Natural gas transportation investments in the US

FERC, the Federal Energy Regulatory Commission, introduced the unbundling of pipeline services in the US with Order n. 636 issued in 1992. In particular, interstate pipeline companies were required to place their production in separate companies, trading and retailing businesses. At present, there are about 160 pipeline companies in the United States, operating over 300,000 miles of pipe. Of this, 180,000 miles

[64] In almost all these market there is a nodal pricing mechanism, called locational marginal price (LMP).

consist of interstate pipelines. A significant level of competition is observed among providers of transportations services (or "pipe-to-pipe" competition)[65].

In the US a merchant logic drives the investment in gas infrastructures. Any party has the right to develop and build gas transportation facilities. The owners bear the entire cost (and risk) of the infrastructures and have full control on the allocation of the corresponding transportation rights. This eliminates any regulatory intervention on the allocation of the infrastructure costs. In particular FERC mandates incremental pricing for the expansion of existing pipelines, recognizing that other forms of pricing are "inconsistent with a policy that encourages competition while seeking to provide incentives for the optimal level of construction and customer choice"[66].

Although there is no central planning activity of the gas transportation network, FERC's authorization process performs a coordination and in some cases a market power mitigation function. The First objective of FERC's authorization is avoiding capacity investments when the demand for transmission services can be satisfied by the existing capacity that shippers are available to release. This check is performed by the sponsor of the investment seeking authorization through an open season procedure.

A second objective pursued by FERC is ensuring that the entire cost of the new investment is borne by the investors. In particular, the concern is that the new pipeline might cause a decrease in the utilization of existing pipelines and the captive costumers might end up paying for the unsubscribed capacity.

A third objective of FERC's assessment can be read in terms of a cost-benefit assessment. FERC requires the applicant for authorization to build a new infrastructure in order to demonstrate that the investment will not have adverse effects on various stakeholders. In particular, for existing costumers the new infrastructure must not result in their rates being increased, nor in a degradation of the service; for landowners and communities, adverse effects might arise as a

[65] Jamasb, T., M. Pollitt, T. Triebs, 2008, Productivity and efficiency of US gas transmission companies: A European regulatory perspective, *Energy Policy,* Volume 36, Issue 9.

consequence of unnecessary construction. Finally, for existing pipelines, in the authorization process of the “Ruby Pipeline” (stretching from Wyoming to Oregon), the Commission clarifies that a negative impact on existing pipelines resulting from genuine competition does not provide ground for denying authorization. In other words, infra-marginal wealth transfers among transportation service providers and network users caused by the investment are not relevant for FERC’s assessment. Investors in the pipeline are protected against the risk that further facilities will displace theirs (the standard “commercial risk”), only to the extent that they hedge in the market, i.e. they sell forward their transmission rights. In this sense the US approach is on the line of the Reference Approach we discussed in the previous section.

In case some adverse effects are identified, the Commission will proceed to evaluate the project by balancing the evidence of public benefits against the adverse effects. Public benefits may include: reaching new customers, eliminating bottlenecks, access to new supplies, lower costs to consumers, environmental benefits, etc.

Finally, FERC approves the tariffs for the services of the new infrastructure. Interstate pipelines are quite free in setting their tariff rate, but the Natural Gas Act (NGA) requires that those rates be "just and reasonable." FERC has translated this principle with the establishment of a cost of service rate making, even though the Commission explicitly recognizes that, in certain situations, also other rate making methods can meet the just and reasonable standard. For example, the Commission has allowed:

- **Selective discounting**, where a pipeline is free to charge any rate between the maximum rate, set at the pipeline's average cost of providing service, and the minimum rate, which is set at the average variable cost of providing service. The pipeline however, must offer such discounts on a non-discriminatory basis;

- **Market-based rates**, provided the applicant was able to show that the pipeline had no market power; and, more recently,

[66] 90 FERC 61,128; Docket No. PL99-3-001, Certification of New Interstate Natural Gas Pipeline Facilities, ORDER CLARIFYING STATEMENT POLICY, Issued February 9, 2000 .

- **Negotiated rates**, under the same condition on the absence of market power and provided the pipeline offered their clients (also) an optional cost-based tariff for a standard service.

7.2.2 Electricity

Regulatory powers on electricity transmission in the US are split between FERC and the States in a complex way. Major transmission investments involve both the FERC and the State Commissions. Network expansions may take place within the regulated framework, in which case FERC has to authorize that investment costs be passed through to customers via the transmission tariffs, or otherwise be merchant.

FERC's current discipline on transmission investment is rather vague when it comes to cost allocation issues. Order 890/2007 contains only the broad principle that methodologies proposed by the party seeking approval for a transmission investment project "fairly assign costs among participants, including those who cause them to be incurred and those who otherwise benefit from them".

In 2010 FERC published for consultation proposals process on Transmission planning and cost allocation[67]. The proposal seeks greater coordination between the transmission planning and the cost allocation processes. Since the transmission planning process involves the identification of expected beneficiaries of the investment, that information is to be the basis for the cost allocation.

As to coordination across regions, cost sharing across regions on a voluntary basis is allowed. Further, FERC has the authority to allocate the cost of new infrastructures to entities that have not entered a voluntary arrangement with the utility proposing an investment, as long as the entity is recognized as a beneficiary from the transmission upgrade. For example, when presented with concerns about parallel path flow, the Commission allows public utilities that can demonstrate that a transaction is a burden on their system to propose (for FERC's consideration) transmission service rates accounting for unauthorized use of their systems.

[67] FERC docket No. RM10-23-000

FERC principles have been implemented differently by different system operators. So far no unambiguously superior solution appears to have been identified, and several cases are settled in front of the Courts . In the following sections we discuss, first, a case in which the PJM market cost-allocation methodology has been successfully challenged by a subset of the network users. We move on to a case in which welfare redistribution issues, like those discussed in section 7.1 appear to have motivated denial of authorization for a project. We then move on to the methodology proposed by Southwest Power Pool (SPP).

7.2.2.1 Cost allocation in the PJM market

In the US the cost of transmission networks, with the exception of the merchant lines, are passed on to the final customers through transmission tariffs. Where a Regional Transmission Organization (RTO) is in place, the RTO decides the transmission investment and the costs are split among the transmission owners operating in the RTO area. Then, each transmission owner passes on those costs to the customers connected to his network, via the transmission tariffs.

The largest power market in the world, PJM includes two structurally different market zones: a coal-based, net export zone to the west, and an urban load center to the east that is largely dominated by newer gas-fired generations. As a result, congestion between eastern and western PJM is common and persistent.

Under its Regional Transmission Expansion Plan (RTEP), PJM allocates differently the cost of transmission system updates necessary to preserve reliability standards and transmission investment to address market efficiency. The allocation of costs for economic upgrades is assigned to zones by the share of locational energy price benefits (reduced load payments) accruing to the zone or by the use of distribution factors if the allocations are within 10 percent of the price benefit allocation[68].

The cost of investments enhancing reliability is allocated differently depending of the voltage level of the new infrastructure. The cost of network elements 500 kV or above are shared on a region-wide basis via a postage stamp rate. It is therefore assumed

[68] A Survey of Transmission Cost Allocation Issues, Methods and Practices PJM, March 2010.

that all the customers benefit equally from these kind of investments. The cost of infrastructures below 500 kV are allocated according a cost-causation criterion based on load-flow analysis, through which the RTO assess the contribution of each market zone to loading the network elements upgraded by the investment.

In 2009, the Illinois Commerce Commission (on behalf of Illinois based utilities) challenged PJM's cost allocation methodology for reliability upgrades, in particular, the postage stamp rate in order to allocate the cost of investment on the 500 kV network. Their argument was that Illinois utilities and costumers would have had to bear significant costs without getting tangible benefits, as all the proposed expansions were planned in the eastern part of the market and they were made not in order to increase reliability but to ease congestions. The Court ruled in favor of the petitioners. In particular, the Court stated that "FERC is not authorized to approve a pricing scheme that requires a group of utilities to pay for facilities from which its members derive no benefits, or benefits that are trivial in relation to the cost sought to be shifted to this members". This ruling has two major implications. On the one hand, it rules out methodologies that force each investment into a predefined category, based on the nature of the benefits that it delivers. The Court ruling recognizes that typically network upgrade yield benefits in different areas, and in reliability and congestion relief in particular. On the other hand, the Court ruling emphasizes the central role of the assessment of the economic benefits in the context of the "beneficiary pays" approach.

7.2.2.2 CAISO approach to cost allocation

California ISO's Transmission Economic Assessment Model (TEAM), developed since 2004, implements a comprehensive approach to quantifying the benefits of and identifying the parties who benefit from transmission network upgrades.

Despite the fact that the assessment is performed at the planning stage, there is no direct link between the welfare analysis performed for the purpose of the investment decision and cost allocation; the former being characterized by a high degree of socialization.

For the purpose of cost allocation facilities operating below 200 kV are assumed to benefit the sub-region (North, East-Central, and South sub-regions) where they are located. The cost of all other investments is socialized among all loads within CAISO's jurisdiction on a MW-hour basis.

A large inter-regional transmission project, the Devers-Palo Verde No. 2 project incrementing the transfer capacity from Arizona to California by 1200 MW, has been recently abandoned after the opposition of the Arizona State Commission.

The project was merchant, therefore cost allocation issues were not relevant for its assessment. Instead the project appears to have been rejected due to its welfare re-distribution implications.

CAISO has applied the simulation technique to show that Devers-Palo Verde No. 2 project is beneficial[69]. In particular, TEAM calculated net benefits deriving from: savings in generation costs, thanks to the increased production from Arizona's generators; reduced transmission congestion; overall increase in network reliability. Off-model analysis showed the possibility to gain benefits from GHG emission reduction.

Notwithstanding the net beneficial effect that was confirmed by the analysis, Arizona Corporation Commission rejected the project. The reason for that was that CAISO did not properly specify the welfare effects in both exporting and importing regions. In particular, since Arizona was to become the exporting region, the Arizona Commission feared that its consumers would have experienced an increase in final prices.

After the rejection of the project, SCE filed a petition to the California Public Utilities Commission to gain permission to construct the Californian portion of the project, even though the updated results of the economic analysis of the project showed that the economic benefits to California customers of building the Arizona portion of the project are now significantly reduced.

[69] CAISO Department of Market Analysis and Grid Planning, February 2005, Economic Evaluation of the Devers-Palo Verde No. 2.

7.2.2.3 Highway-byway methodology

In April 2010 Southwest Power Pool (SPP), the RTO of the central Southern United States, proposed a simple highway-byway cost allocation methodology, which was approved by FERC.

The highway-byway approach has two layers of cost allocation for transmission projects, regional and zonal. The transmission charges are assigned mainly to loads under this methodology. The allocation of transmission upgrade costs is differentiated according to the voltage level of the facilities, subjects to the upgrade. Specifically, the costs of upgrade are allocated in the following way:

- Facilities operating at 300 kV - 100% of the costs are allocated across the region on a postage-stamp basis (so-called highway approach);
- Facilities operating between 100 kV and 300 kV - 1/3 of the costs are allocated on a regional postage-stamp basis and the remaining 2/3 of the costs are borne by the zone where facilities are situated;
- Facilities operating at or below 100 kV – 100% of the costs are allocated to the zone where facilities are situated (byway approach).

The interesting aspect of the SPP's case is that FERC has approved a cost allocation methodology that does not appear to relate cost allocation to any measure of the economic benefits gained by the different stakeholders.

7.3 Assessment

Transmission investments, besides increasing welfare, may cause a large surplus redistribution among geographic areas and, within an area, between generators and consumers.

The share of the cost of the new infrastructure allocated to each stakeholder is just one component – and sometimes not the most relevant – of the economic impact of the investment on that stakeholder.

The relevant political question is whether some wealth-transfer effects of the investment should be sterilized through appropriate policy measures. By leaving the pre-investment surplus allocation unchanged, that would facilitate reaching a consensus on the construction of positive-net-valued investments. This issue might be particularly relevant for investments whose effects are cross-border, in particular if in the exporting country the political weight of electricity price increases is higher than the political weight of increased profits obtained by the generators.

We have identified two cases where public policies appear to reflect surplus redistribution concerns. The French NOME project, that fixes the existing allocation of the nuclear rent between the generators and the French customers. In the US, the Devers-Palo Verde No. 2 case appears to be an example of a net-positive valued investment rejected due to its (infra-marginal) surplus redistribution effects.

Once the general question on whether and to what extent to expose the entire impact to the stakeholder is answered, a cost-sharing rule based on the benefit obtained by each country or stakeholder appears natural and its implementation relatively straightforward. Nevertheless even in the US, where the “beneficiary pays” principle seems to be well established, we found that methodologies that do not link the cost allocation to any measure of the economic benefits gained by the different stakeholders are still extensively implemented.

Once this issue is sorted out, winners and losers can be easily identified with our methodology of chapter 4 and 5, and, therefore sharing the investment costs based on the benefits will be easy.

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Appendix: Benefit-based and utilization-based cost-allocation methodologies

In this Appendix we discuss the relationship between the "benefit-based" approach to sharing the costs of network investments having material cross-border effects, introduced in section 7.1, and the "utilization-based" approach developed within the context of the inter-TSO compensation mechanism.[70] Under the benefit-based approach the cost of the network upgrade is allocated proportionally to the net surplus change caused by the investment for each class of stakeholders. The information about each stakeholder's surplus change caused by the investment is a byproduct of the cost-benefit analysis on which the investment decision is based. The ITC work-stream was started in order to address cost-sharing issues related to existing infrastructures, planned and financed mainly in a National perspective. In this context cost-sharing rules based on the network's utilization have been proposed to compensate "transit" countries, i.e. countries whose transmission network carries power flows originating and terminating in other countries. Alternative methodologies have been developed to assess the impact on a country's network of net-injections taking place in other countries, or in each node of the other countries' networks. We will later refer to these methodologies as "ITC methods".

We see two main differences in the cost-sharing approaches based on benefits and on utilization. The first difference is in the drive to share the investment's cost. In the benefit-based approach, costs are split among the stakeholders proportionally to the welfare increase obtained by each stakeholder thanks to the network upgrade. In the utilization-based approach, costs are split according to a measure of the utilization of the new infrastructure by each stakeholder, i.e. according to the flows on the new infrastructure caused by the stakeholder's injections or withdrawals. The difference in the drive to share the investment costs can determine a different perception of fairness of the two approaches.

[70] For a discussion of those methodologies see DG:

DG TREN (2008) Consultation document o the inter-TSO compensation mechanism and on harmonization of the transmission tarification. Towards fair and non-discriminatory arrangements for trans-european cross-border power flows. 9 December 2008. DG TREN/C2.

DG TREN (2006) Study on the further issues relating to the inter-TSO compensation mechanism. 13 February 2006. Frontier Economics Limited, CONSENTEC.

The second area where the benefit-based and the utilization-based approaches depart is the network modeling methodology. Each ITC-method relies on discretionary assumptions. The nature of those assumptions can be intuitively illustrated in the context of the so called "Marginal Participation" method[71]. The Marginal Participation method is based on load-flow models, which measure the incremental flow through each network element caused by an incremental net-injection at a node (the "sensitivities"). The sensitivity values obtained through the load flow model crucially depend on the discretionary choice of the "swing node", the node where the incremental net-injection is assumed to be balanced. That discretionary element is not present in the modeling framework proposed in Chapter 4 to assess the benefits of the network upgrades, based on an optimal dispatch model.

In highly simplified terms, the indeterminacy which in the load-flow model is solved by the discretionary choice of the swing-bus, disappears in the optimal dispatch model. In particular, in the optimal dispatch model any increase in net-injections is balanced in the welfare-maximizing way. For example, the effect of a 10 MW increase in net-injections in node X on line *n* will be assumed to be matched by -10 MW net-injections:

- At the location of the most expensive generator, by the optimal dispatch model;
- At the (arbitrarily selected) swing-bus, by the load flow model

Although an ITC-method based on an optimal dispatch model is conceivable, such a method would be remarkably different from the ITC-methods proposed so far. In particular, an ITC-method based on an optimal dispatch model would rely on economic information whilst the ITC-methods proposed so far are exclusively based on engineering and do not take into account any economic considerations.

[71] See DG TREN (2006) *Study on the further issues relating to the inter-TSO compensation mechanism*. 13 February 2006. Frontier Economics Limited, CONSENTEC, pp. 26-28.

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