



DEVELOPMENT OF BEST PRACTICE RECOM- MENDATIONS ON REGULATORY INCENTIVES PROMOTING INFRASTRUCTURE INVESTMENTS

FINAL REPORT



E-Bridge
competence in energy



DEVELOPMENT OF BEST PRACTICE RECOMMENDATIONS ON REGULATO- RY INCENTIVES PROMOTING INFRA- STRUCTURE INVESTMENTS

Study for the Energy Community Secretariat
Final report

23 November 2011

Author:

Dr. Jens Büchner

Dr. Martin Bandulet

Dr. Wolfgang Elsenbast

Dipl.-Betriebsw. Philipp Schmidt

E-Bridge Consulting GmbH disclaims liability for any direct, indirect, consequential or incidental damages that may result from the use of the information or data, or from the inability to use the information or data contained in this document.

The contents of this presentation may only be transmitted to third parties in entirety and provided with copyright notice, prohibition to change, electronic versions' validity notice and disclaimer.

E-Bridge Consulting, Bonn, Germany. All rights reserved.

Development of Best Practice Recommendations on Regulatory Incentives Promoting Infrastructure Investments

1. INTRODUCTION	4
2. WORK APPROACH	5
3. DESCRIPTION OF INTERNATIONAL EXPERIENCE WITH INVESTMENT INCENTIVE SYSTEMS	7
3.1 Overview	7
3.2 REGIONAL INVESTMENT PLANS	8
3.2.1 International Experience	8
3.2.1.1 European Regulation	8
3.2.1.2 Nordic Investment Plan	9
3.2.1.3 Investment Plan by PJM	11
3.2.2 Overview of current Network Models	13
3.2.2.1 Overview	13
3.2.2.2 PRIMES	14
3.2.2.3 COMPETES	15
3.2.2.4 European gas model	15
3.3 REGULATORY EX-ANTE TESTS	16
3.3.1 Overview	16
3.3.2 Australia	17
3.3.3 New Zealand	19
3.3.4 FERC – USA	20
3.3.5 California – USA	22
3.3.6 The Netherlands	22
3.3.7 France	23
3.3.8 Austria	24
3.3.9 Norway	24
3.3.10 Germany	25

3.4 INCENTIVE MECHANISM	26
3.4.1 Overview	26
3.4.2 Sliding scale in the UK	27
3.4.2.1 Common sliding scale	27
3.4.2.2 Menu of sliding scales	31
3.4.3 Bonus-malus system in The Netherlands	36
3.4.4 The DPP/LPP mechanism in New Zealand	36
3.4.5 Individualising of the incentive scheme	37
3.5 EXEMPTIONS FROM REGULATION	39
3.5.1 US	39
3.5.2 Australia – Murraylink	40
3.5.3 Europe	40
3.6 TENDERING	41
3.6.1 Overview	41
3.6.2 Argentina	42
3.6.3 Offshore cables – UK	43
3.6.4 Capacity expansion agreements – UK	43
3.7 OTHERS	45
3.7.1 Open Season	45
3.7.2 Auction revenues	47
4. EVALUATION OF INTERNATIONAL INVESTMENT INCENTIVE SYSTEMS	49
4.1 OVERVIEW	49
4.2 (REGIONAL) INVESTMENT PLANS	49
4.3 REGULATORY EX-ANTE TESTS	52
4.4 INCENTIVE REGULATION	52
4.5 EXEMPTIONS FROM REGULATION AND TENDERING	53
5. FINDINGS ON THE STATUS QUO IN THE 8TH REGION AND IDENTIFICATION OF ROOM FOR IMPROVEMENT	55
5.1 OVERVIEW	55
5.2 INVESTMENT INCENTIVES IN ELECTRICITY	55
5.3 INVESTMENT INCENTIVES IN GAS	58
5.4 POSSIBLE ROOM FOR IMPROVEMENTS	61

6. RECOMMENDATIONS FOR THE ENERGY COMMUNITY.....	63
6.1 OVERVIEW OF THE RECOMMENDATIONS FOR IMPROVEMENTS	63
6.2 Legislation measures	66
6.3 Regulatory means	67
6.3.1 (REGIONAL) INVESTMENT PLANS	67
6.3.1.1 Drivers for investments – the investment need.....	67
6.3.1.2 Obligation to operate.....	67
6.3.1.3 Evaluation of social-economic benefits.....	68
6.3.2 Negative incentives	74
6.3.3 Multinational projects and the regulatory gap	74
6.4 INVESTMENT BUDGETS	77
6.4.1 Scope of the investment budget	77
6.4.2 Term and expiry of the investment budget	77
6.4.3 Ex-ante approval	78
6.4.4 Ex-post monitoring	82
6.4.5 Supplementary economic incentives	82
RELEVANT LITERATURE.....	85
LIST OF FIGURES AND TABLES.....	89

1. INTRODUCTION

Attracting investments is of core relevance for both the development of liquid energy markets in South East Europe (SEE) and security of supply. Investments in new transmission line projects remain a key requirement for the development of liquid and competitive electricity and gas markets in SEE. Where bottlenecks exist, market integration and cross border trade cannot develop appropriately. Facilitating and stimulating new investments in congested areas is therefore a core responsibility of both national legislation and regulatory practise.

The regulators have a clear responsibility to ensure a regulatory framework that allows the realization of infrastructure investments. Both the gas and electricity regulations require regulators to take investment costs into account in their tariff base. Additionally, regulators can provide a number of other regulatory instruments facilitating investments. As a general rule investment incentives, which are interpreted into regulatory regime, are preferred over exemptions from regulation. Before considering an exemption, it is the responsibility of national regulators to assess other options of facilitating investments in new transmission capacities, namely to develop regulatory investment incentives for building new gas and electricity transmission projects.

The 2010 Work Programme of both the Energy Community Regulatory board (ECRB) Electricity Working Group (EWG) and ECRB Gas Working Group (GWG) planned a project on investigating possible incentives for promoting infrastructure investments. E-Bridge is chosen as Consultant for this study because of widespread knowledge in

incentive regulation and recent experience in topics of investment regulation.

The study provides a description of international practise of investment incentives, describes the status quo of investment incentive regulation in the 8th region and identifies the room of improvement. Further, concrete recommendation ("best practises") will be drawn after a meeting with the ECRB and ECS ECRB Section.

The study is based on own research of E-Bridge and takes account of recent research like the Frontier Economics/Consentec study for the European Commission ("Improving Incentives for investment in electricity transmission infrastructure", 2008) and recent reports of ECRB ("Cooperation of Regulators with Regard to Cross-Border Investment Projects", March 10, 2010 and "Regulatory Framework for the Development of the Energy Community Gas Ring", March 10, 2010) in order that no relevant work is doubled.

The report in hand

- asses the existing models for regulatory investment incentives in ga and electricity netowrks in the EU, The Contracting Parties of the Energy Community or elsewhere
- summarizes the findings on the status quo in the 8th Region and identifies room for improvement
- develops recommendations of incentives for investments in gas and electricity networks
- develops the necessary next steps.

2. WORK APPROACH

The study follows the work approach depicted in the following figure.

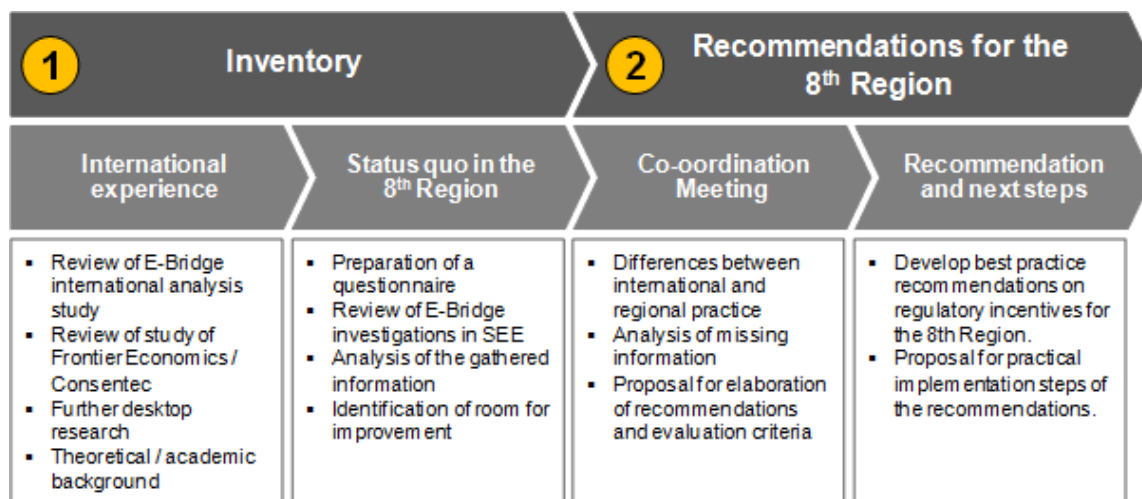


Figure 1: : Work approach

It is divided into two phases: 1) Inventory phase (work packages 1 and 2) and 2) recommendation phase (work packages 3 and 4).

The study addresses the possible approaches for regulatory measures incentivizing investments in gas and electricity network capacity.

In detail, it consists of:

- Assessment of the existing models for regulatory investment incentives in electricity and gas networks in the EU, the Contracting Parties of the Energy Community or elsewhere (e.g. US market et al) and theoretical/academic background on the topic;
- Findings on the status quo in the Energy Community - comprising Albania, Bosnia and Herzegovina, Croatia, the Former Yugoslav Republic of Macedonia, Montenegro, Serbia, UNMIK¹, Bulgaria, Greece, Hungary, Romania, Slovenia, Italy² - and identification of room for improvement³;
- Co-ordination meeting;
- Preparation of recommendations for the Energy Community Region.

¹ Under UN Resolution 1244

² According to the decision of the Energy Community Ministerial Council on establishing the 8th Region (decision 2008/O2/MC-EnC; <http://www.energy-community.org/pls/portal/docs/296192.PDF>) Italy-'s membership to the 8th Region is limited to its interconnections with the other markets of the 8th Region

³ Moldova and Ukraine by default became members of the 8th Region upon becoming members of the Energy Community. Given that both countries have not yet been members of the 8th Region by the date of commissioning the present study, Moldova and Ukraine are not reflected in this report

3. DESCRIPTION OF INTERNATIONAL EXPERIENCE WITH INVESTMENT INCENTIVE SYSTEMS

3.1 OVERVIEW

This study is about providing investment incentives to electricity and gas network operators. These incentives shall encourage network operators to:

- Build network facilities, as required to meet the market's demand for network capacities as the basic requirement for promoting competition.
- Build the most economically network facilities

Both dimensions are interlinked, as the main driver for new investments is an attractive rate of return for network operators. The European Gas and Electricity Directives⁴ require network operators to provide sufficient network capacities to meet reasonable demand. This reflects the understanding of a natural monopoly representing an essential facility for the development of competition. According to the understanding of the European Commission's services the respective obligation of net-

⁴ For the electricity sector: Art 2.4 Directive 2003/54/EC (2nd package) and Art 2.4 Directive 2009/72/EC (3rd package); for the gas sector Art 2.4 Directive 2003/55/EC (2nd package) and Art 2.4 Directive 2009/73/EC (3rd package). The Energy Community acquis includes the relevant 2nd package Directives (http://www.energy-community.org/portal/page/portal/ENC_HOME/ENERGY_COMMUNITY/Legal). The 3rd package has been adopted by the Energy Community Ministerial Council at its meeting on 6 October 2011 by decision MC 2011/02 for implementation into the Contracting Parties' legislation by 2015 the latest (<http://www.energy-community.org/pls/portal/docs/1146182.PDF>)

work operators involves the responsibility to sort out long term congestion by adding new capacities to their system. Still, only if a network operator is able to earn a sufficient rate of return on an investment, it is assumed to make the necessary investment. Also the European Gas and Electricity Directives therefore include references to the economic feasibility of a project. The "attractiveness" depends on various aspects. Most importantly, the rate of return must reflect the associated risks of the investment appropriately. The most common regulatory means to increase investment incentives are therefore

- To increase the allowed rate of return: and/or
- Reduce the regulatory risks, namely the uncertainties faced by long term investment related to possible short- and medium- term changes of regulatory rules.

In the following, we describe relevant international experience in providing investment incentives. The international review focuses on the incentive systems in the UK, Norway, the Netherlands, New Zealand, Australia, Canada, Argentina and the U.S., since those countries have the profound experience with incentive systems for costs of capital. Further important European countries like France and Germany are analyzed in addition.

For the purpose of a structured discussion, it is useful to differentiate the following incentive schemes:

- Regional Investment Plans, which shall improve the coordination between network operators and market participants by making the need for new investments transparent and ensuring that new investments are appropriately considered in the network expansion plans.
- Regulatory ex-ante tests, which reduce the regulatory risk and/or increase the rate of return of an investment

- Incentive mechanisms, which provide incentives to reduce costs below or exceed returns above target values
- Exemptions from regulation, which allow meeting bank requirements related to rate of returns higher than within the regulated business or in case of exclusive use of capacities
- Tendering for new investments to encourage the investments from "independent" investors.

Combinations of the approaches are possible. For example, an introduction of a tendering procedure in the UK, as planned, could lead to coexistence of different concepts for regulating costs of capital.

Network operation must comply with certain criteria, namely to ensure a safe and secure operation of the grid and to meet the market needs. In order to ensure that the network operators comply with these general requirements, quality criteria are introduced. Quality regulation is useful in energy networks as without a quality element there is a strong incentive to reduce the quality to excessive cost reasons. The specific quality standards, if existent in a form of quality regulation, are normally set by the NRA, based on indicators.

In general, a quality control will result in replacement and expansion as well as restructuring investment incentives if the investment incentives are strong enough, i.e. how the penalties and bonuses relevant to quality are set. Quality regulation is often not established until yet, especially in the gas sector, since no criteria are defined.

In principle, a system of investment regulation may conflict with a system of quality regulation as investment incentives are influenced by quality regulation. However as quality regulation is more likely to be regarded as a correction system for network expansion and unless it is

financially significant, it seems to be useful to neglect this influence in the system of investment regulation.

The assessment covers both the gas and electricity sector. The main regulatory mechanism is similar in both industries, but broader experience has been gained in the electricity industry.

3.2 REGIONAL INVESTMENT PLANS

Investment plans can provide an efficient investment incentive, especially if a regulatory acknowledgement of the plan's projects as necessary investment is linked to a regulatory confirmation on recognising the necessary project costs in the regulated asset base. The, herewith, provided predictability has positive effects on the project's financing requirements and bankability. Such risk reduction can be an incentive to invest

3.2.1 INTERNATIONAL EXPERIENCE

3.2.1.1 EUROPEAN REGULATION

Since 2009 regional investment plans are part of the European transmission network regulation. Regulation (EC) No. 715/2009⁵ defines in Art. 8 that the a communi-

⁵ Regulation (EC) 715/2009 of the European Parliament and the Council on conditions for access to the natural gas transmission networks and repealing Regulation (EC) No 1775/2005, OJ L 211 p 3 et seq (14.8.2009); hereinafter "Regulation (EC) 715/2009". Until the implementation of the 3rd legislative package by 2015 the latest, including Regulation (EC) 715/2009, the 2nd packages' Regulation EC) No 1775/2005 (OJ L 289 p 1 et seq (03.11.2005) remains applicable in the Energy Community Contracting Parties. Regulation EC) No 1775/2005 does not require a community-wide network development plan. Network operators of the Energy Community, however, are already involved in the related Plan preparations by ENTSO-E (www.entsoe.eu; for electricity and ENTSO-G (www.entsog.eu; for gas).

ty-wide network development plan that in particular should build on national investment plans taking into account regional network plans and if appropriate, community aspects of the network planning (including the guideline for Trans-European energy networks in accordance with the decision No. 1364/2006/EC of the European Parliament and the Council⁶). Article 12 Regulation (EC) No. 715/2009 further defines that TSOs shall establish regional cooperation within ENTSO for gas to contribute to the tasks referred in Art. 8. In particular they shall publish a regional investment plan every two years and may take investment decisions based on regional investment plan. For the electricity sector the Regulation No. 714/2009 on conditions for access to the network for cross-border exchanges is analogue⁷. Notably TSOs are only forced to publish regional investment plans; investment decisions may base on that plan. The cooperation between the TSOs, especially in the context of investment planning, will be enhanced by the European network of Transmission System operators for Electricity and Gas (ENTSO-E/ENTSOG⁸). The 3rd package aims at deepening market integration by harmonization of national regulatory frameworks and improvement of interconnections. ENTSO-E and ENTSOG are required to develop and publish a community-wide ten-year network development plan every two years. As part of the plan, ENTSO-

⁶ OJ L 262, p 1-23 (22.9.2006).

⁷ OJ L 211, p 1 et seq (14.8.2009); hereinafter „Regulation No. 714/2009“.

⁸ ENTSO-E is an integration of six predecessor associations: ATSOI, BALTSO, ETSO, NORDEL, UTCE and UKTSOA. They were responsible for the regional enhancement of cooperation between the TSOs. ENTSOG is the parallel organization for gas, founded by 31 TSOs from 21 countries in December 2009. The mentioned regulations for electricity and gas are part of the 3rd package, adopted in 2009 and entering into force in March 2011

E/ENTSOG shall develop a model of the European network in order to assess the resilience of the utility system and to project possible solutions to meet congestions and realize needed investments.

3.2.1.2 NORDIC INVESTMENT PLAN

In the Nordic area the regional investment plans to be developed replace the *Nordic Grid Master Plan* that was implemented by Nordel. This plan was a voluntary cooperation between the TSOs in Denmark, Finland, Iceland, Norway and Sweden in regard to utility-investments. Publishing regional investment plans is now mandatory but the investment decisions do not have to be based on these plans.

The successful Nordel co-operation on system planning aims at developing the grid from a Nordic perspective taking into account the international aspects and paying attention to environmental impacts. In 2007, it was decided to make a new analysis of the potential for future investments in the power infrastructure beyond 2015. The analysis is called *Nordic Grid Master Plan 2008*. The main outcomings from the Nordel studies resulting from the master plan are:

Congestion management: Congestions are in general handled where they are physically located. Structural congestions are removed or reduced by grid investments whenever socio-economically viable, otherwise market splitting is applied, i.e. dividing the market into separate price areas. Temporary congestions shall be handled by counter trade (redispatching), if possible.

Transit compensation: Transit compensation will have consequences for the socio economic profitability of new investments. The costs and benefits of transit and trade are taken into consideration when proposed investments in grid reinforcements are analyzed.

The Master Plan identifies cross-section reinforcements which will be cost-effective for the years 2015 and 2025. This was carried out by means of a socio-economic cost-benefit calculation. Consumption and production of electricity were estimated in the Nordel scenarios for 2015 and 2025. The scenarios illustrate different possible pathways for power infrastructure requirements. Three scenarios are analyzed: A business-as-usual reference for 2015 (BAU 2015) and two alternative BAU-scenarios for 2025 with differences in production: a scenario focusing on climate and international integration (Climate & Integration) and a scenario focusing on national solutions (national focus). The Climate & Integration 2025 scenario uses a more positive energy balance in Norway and Sweden and a poorer energy balance in Denmark compared to the other scenarios. This is caused by the higher CO₂ prices in this scenario, which lead to a higher price difference and higher benefit for new connections between Denmark and Norway/Sweden.

Costs and benefits for all potential reinforcements have been calculated and analyzed. The costs for the reinforcements as well as the increase in capacity they provide have been estimated using "standard values". The analysis includes the calculation of benefits from

- Improved market efficiency,
- Improved security of supply and
- Reduced electrical losses.

Furthermore, market power has been generally discussed but is not included in the evaluation. The robustness to the different future pathways (scenarios) has been analysed in the form of a sensitivity analysis. The mutual effect of the reinforcements has been quantified.

Results:

The results of the analysis show that some internal Nordic reinforcements are highly beneficial. Areas with significantly high benefit from internal Nordic reinforcements are found in Mid-Norway, the grid around Oslo (Norway) and the connection between Sweden and Norway through the West-Coast corridor and finally in the Arctic region. Reinforcements in these three areas show a positive cost-benefit ratio in all scenarios.

Apart from these projects, the analysis and other considerations indicate other potential reinforcements. These results are not conclusive and further analysis is required. In the Climate & Integration 2025 scenario, some additional lines get a positive cost-benefit value. This is found for the connections:

- Norway North - Sweden
- Sweden - Denmark-West
- Sweden - Denmark-East
- Norway - Denmark-West
- Norway - Denmark-East.

These potential reinforcements should be observed as climate issues and wind power production will become more important in the future.

The Nordel area also includes a border between the hydropower-dominated area in Norway/Sweden and the thermal-power dominated area in the south with connections to the Continent. This leads to significant benefits from external Nordic interconnectors interfacing with the

Continental thermal market.⁹ The analysis shows a positive socio-economic value from establishing or reinforcing connections from Norway to Germany/the Netherlands and from Denmark/Sweden to Poland/Germany/the Netherlands.¹⁰

Further the analysis shows that the different reinforcements are not mutually exclusive. The benefit is typically reduced by less than 10% if another connection is built at the same time. There has been no dialogue with the TSO's outside the Nordic countries to discuss connection costs and/or limitations in the receiving grid. The need for and cost of internal reinforcements are not included in the calculation.

3.2.1.3 INVESTMENT PLAN BY PJM

In the USA, there are experiences with regional investment plans, made by PJM Interconnections, an independent regional transmission organization (RTO) that operates in several states. PJM conducts a long-range Regional Transmission Expansion Planning (RTEP) that employs a 15-year planning horizon. PJMs planning began in 1997 with its first regional investment plan approved in 2000.

PJM's RTEP identifies transmission system upgrades and enhancements to ensure the operational, economic and reliability requirements of PJM customers. PJM's region-

⁹ This historical aspect may in the future be supplemented by a huge potential for offshore and coast-based wind power production in the Nordel area as well as in northern Continental Europe.
¹⁰ The Nordel analyses considered the costs for those lines. Other studies indicate that such reinforcements show a potential for being profitable. Further studies of the lines will be made in the multiregional planning process. Planning groups will be started within Nordel for a western and an eastern planning area.

wide RTEP approach integrates transmission with generation and load response projects to meet load-serving obligations. PJM currently applies planning and reliability criteria over a fifteen-year horizon to identify transmission constraints and other reliability concerns. Transmission upgrades to mitigate identified reliability criteria violations are then examined for their feasibility, impact and costs, culminating in one plan for the entire PJM footprint.

The rules and procedures for the RTEP process are set forth in Schedule 6 of the PJM Operating Agreement

It is set out that the RTEP shall conform to the applicable reliability principles, guidelines and standards of Northern American Electric Reliability Corporation (NERC), Reliability First Corporation, Southeastern Electric Reliability Council (SERC), and other applicable regional reliability councils. The Regional Transmission Expansion Plan reliability criteria shall include, Office of the Interconnection planning procedures, NERC¹¹ planning standards and NERC Regional Council planning criteria.

The RTEP Planning Committee shall be open to participation by (i) all transmission customers, and applicants for transmission service; (ii) any other entity proposing to provide transmission facilities to be integrated into the PJM region; (iii) all members; (iv) the electric utility regulatory agencies within the States in the PJM region and the State Consumer Advocates; and (v) any other interested entities or persons and shall provide technical advice and assistance to the Office of the Interconnection in all aspects of its regional planning functions.

¹¹ North American Electric Reliability Corporation; www.nerc.com.

For the content of the RTEP it is set out that the RTEP shall consolidate the transmission needs of the region into a single plan which is assessed on the bases of maintaining the reliability of the PJM region in an economic and environmentally acceptable manner. Further the RTEP shall reflect transmission enhancements and expansions; load forecasts; expected demand response; and capacity forecasts, including generation additions and retirements, for at least the ensuing ten years. The RTEP shall (i) avoid unnecessary duplication of facilities; (ii) avoid the imposition of unreasonable costs on any transmission owner or any user of transmission facilities; (iii) take into account the legal and contractual rights and obligations of the transmission owners; (iv) provide, if appropriate, alternative means for meeting transmission needs in the PJM region; (v) strive to maintain and, when appropriate, to enhance the economic and operational efficiency of wholesale electric service markets in the PJM region; (vi) provide for coordination with existing transmission systems and with appropriate interregional and local expansion plans; and (vii) strive for consistency in planning data and assumptions that may relieve transmission congestion across multiple regions. The Regional Transmission Expansion Plan shall be developed in accordance with the principles of interregional coordination with the transmission systems of the surrounding regional reliability councils. The recommended plan shall identify enhancements and expansions that relieve transmission constraints and which, in the judgment of the Office of the Interconnection, are economically justified. Each year, concurrent with the PJM Board's consideration and approval of the reliability-based transmission enhancement and expansions to be included in the Regional Transmission Expansion Plan, the Office of the Interconnection shall obtain PJM Board approval of the assumptions to be used in performing the market efficiency analysis to identify enhancements or expansions that could relieve transmission constraints that have an economic impact ("economic constraints"). Such assumptions shall include, but not be

limited to, the discount rate used to determine the present value of the total annual enhancement benefit and total enhancement cost, and the annual revenue requirement, including the recovery period, used to determine the total enhancement cost. The discount rate shall be based on the transmission owners' most recent after-tax embedded cost of capital weighted by each transmission owner's total transmission capitalization.

To assure that new economic-based enhancements and expansions included in the Regional Transmission Expansion Plan continue to be cost beneficial, the Office of the Interconnection annually shall review the costs and benefits of constructing such enhancements and expansions.

In accordance with those rules, PJM prepares a plan for the enhancement and expansion of transmission facilities in the PJM region. Additionally, the PJM manuals describe the details of the RTEP process.

The planning process consists in particular of the reliability planning and the market efficiency assessment. Therefore, the following areas are analyzed:

- The need and drivers for a regional transmission expansion plan
- Reliability planning overview
- Specific components of reliability planning and the stakeholder process
- Interconnection request drivers of RTEP
- Market efficiency planning review
- Specific components of market efficiency planning and the stakeholder process.

These tasks of the annual RTEP planning cycle for the 15-year plan are often analyzed parallel. Specific key drivers for the plan are several reliability assessments as well as

an assessment of the performance in previous years (e.g. emerged congestions). Generator and transmission interconnection requests are taken into account as well. Another key driver is the activities under the PJM committee structure, especially, the Planning Committee (PC), the Transmission Expansion Advisory Committee (TEAC) and the Subregional RTEP Committee.

The cumulative effect of these drivers is analyzed through the PJM Region transmission planning process to develop a single RTEP which recommends specific transmission facility enhancements and expansion on a reliable and environmentally sensitive basis and in full consideration of economic and market efficiency analyses. To establish a reference point for the annual development of the RTEP reliability analyses a 'baseline' analysis of system adequacy and security is necessary to identify areas where the system, as planned, is not in compliance with applicable NERC and the applicable regional reliability council (Reliability First or SERC) standards.

The reliability planning consists of a near term and a long term view. System conditions revealed as near violations will be monitored and remedied as needed in the following year near-term analysis. Violations that occur in many deliverability areas or severe violations in any one area will be referred to the long term analysis for added study of possible more robust system enhancement. RTEP reliability planning, through the operation of the TEAC and Subregional RTEP Committees, provides interested parties with the opportunity to review and provide input to all phases of the reliability planning analyses.

Market efficiency analysis is performed as part of the overall PJM Regional Transmission

Expansion Planning (RTEP) process to accomplish the following two objectives:

- Determine which reliability upgrades, if any, have an economic benefit if accelerated.
- Identify new transmission upgrades that may result in economic benefits.

The process begins with the determination of the congestion drivers that may signal market inefficiencies. PJM will collect and publicly post relevant drivers. These metrics will be reviewed by PJM and all stakeholders to assess the system areas that are most likely candidates for market efficiency upgrades. Following the evaluation of congestion drivers and solicitation of remedies, PJM will initiate an analysis phase which examines the potential economic costs and benefits that may be associated with any upgrades specified during the reliability analysis and will perform annual market simulations and produce cost / benefit analysis of projects specifically targeted for economic efficiency. The net present value of annual benefits will be calculated for the first 15 years of upgrade life and compared to the net present value of the upgrade revenue requirement for the same 15 year period.

The final list of reliability projects and market efficiency projects will be presented and discussed at a TEAC meeting. At this TEAC meeting PJM will review all the market efficiency plans resulting from this cycle of market efficiency studies. Recommended projects will be taken to the PJM board for endorsement.

3.2.2 OVERVIEW OF CURRENT NETWORK MODELS

3.2.2.1 OVERVIEW

Regional investments plans should rely on best information available. For gathering those information network models are developed. The essence of a network model is to describe the energy markets under realistic projections of the future of the energy market. A network model relies on a large computer-based simulation of real

electricity markets, including details of the suppliers and the network and environment factors like demand, fuel prices and government policies.

The models typically try to rely on external sources (like IEA, OECD, etc.) for the scenario assumptions. The assumptions on behavior of the suppliers are particularly interesting, because it is possible to include strategic behavior. Typically network models are long run projections of 15 - 20 years or so ahead. The output of the market models is flexible, but typically includes price changes, changes of production costs and social welfare considerations; issues like supply security can be included.

Thus, market models can be used for the analysis and assessment of proposed mergers, market design arrangements (market coupling or zonal pricing), government policy (like CO₂ emission trading scheme (ETS), or increased energy efficiency), but also network investment analysis. Depending on the degree of detail, it is fairly straightforward to run an analysis assuming big network investment projects and compared with a counterfactual without the investment.

We discuss three examples of network models, PRIMES, COMPETES and the planned pan-European gas-model developed by European regulators as those models are interesting in the European context.

3.2.2.2 PRIMES

PRIMES model is a mathematical model prepared by the National Technical University of Athens, E3M-Lab, Greece,

for the European Commission's Directorate General for Transport and Energy (now Energy, DG TREN).¹²

The models which are the core calculator for a larger model called Energy-Economy-Environment system, include:

- Geographical coverage
- Each EU-25 member-state taken individually; in addition candidates and neighbours, such as Norway, Switzerland, Bulgaria, Romania, Turkey
- Network coverage
- Electricity and gas interconnections within Eurasia
- Time frame
- 2000 to 2030 by five-years periods
- Seasonal and daily patterns for electricity, steam and gas load

PRIMES output include (per country and time period):

- Detailed energy balance (Eurostat format)
- Transport activity, modes/means and vehicles
- Association of energy use and activities
- Power system investment and use of plants
- Energy supply per subsystem
- Energy costs, prices and investment
- Emissions and concentrations from energy.

¹² The brief characterization below relies strongly on a June 2006 presentation by Prof. P. Capros from the E3M-Lab – NTUA in Athens

Notably, a big study called TEN-ENERGY-INVEST (CESI et al. 2005) from 2005 for the EU Commission DG TREN explores the potential and cost and benefits of the European transmission priority projects up to 2023. For their calculations, the authors rely on simulations made for instance with PRIMES.

3.2.2.3 COMPETES

COMPETES stands for Comprehensive Market Power in Electricity Transmission and Energy Simulator. This model is developed by ECN Amsterdam. The model was originally developed for the Dutch ministry of economics.

COMPETES covers twenty European electricity markets. It has recently been expanded to include a detailed picture of the German power market allowing a 10-zone projection for 2020.

Virtually all generation companies in the twenty countries are covered by the input data of the model. The user can specify which generation companies are assumed to behave strategically and which companies will be allocated to the so-called 'competitive fringe' (i.e. the price takers). The model calculates the equilibrium behavior of the generators - and the resulting outcomes - by assuming that they simultaneously try to maximise their profits.

With regard to consumer behavior, the present version of the model considers 12 different levels of demand, based on the typical demand during three seasons (winter, summer and autumn/ spring) and four time periods (super peak, peak, shoulder and off-peak). The consumers are assumed to be price sensitive by using decreasing linear demand curves depending on price. The number and duration of periods and the price elasticity of demand in different periods are user-specified parameters.

Transmission of electricity among countries is constrained both by power transmission distribution factors (PTDF),

which is a linearised "DC load flow" representation of the transmission network, and path-based restrictions, which reflect the contractually allowed flows among countries. The linearised load flow model recognizes the existence of controllable DC lines between non-synchronized markets (UK, UCTE, and Nordpool). Interface constraints in the path-based restrictions include constraints between individual pairs of countries, as well as multicountry interfaces (for instance, aggregate exports from Germany to the Netherlands and to France are constrained). Note that the physical line capacity is generally larger than the contractually permitted amounts and this difference is also reflected in the COMPETES model.

3.2.2.4 EUROPEAN GAS MODEL

Recently, the European Regulators seized the initiative to develop a pan-European gas network.

Whereas the initiative comes from the European regulators, the TSOs will actually develop the model and subsequently the network planning. The TSO tend to be sympathetic towards the idea. Planned is a Europe wide 10-year network development plan for the gas network. The background is the third Energy package with its emphasis on the improvement of investments. This emphasis reflects the issue of transparency and supply security.

First approaches follow two lines:

- Top down: the integrated development of a European perspective
- Bottom up: constructing a European picture from national data.

The model includes and in fact aims at the identification of infrastructure projects, and considers aspects such as:

- Technical aspects, cost components, implementation risks, effect on supply security,
- Identification of alternative projects.

3.3 REGULATORY EX-ANTE TESTS

Similar to investment planning, regulatory ex-ante tests develop positive incentives for investments where they are linked to an acknowledgment of the project related costs in the regulatory asset base.

3.3.1 OVERVIEW

An important regulatory mean to increase incentives to invest are to reduce the regulatory uncertainties. Regulatory uncertainties result from regulatory tariff reviews during the lifetime of the assets, which may declare investments inefficient and which lead to reduced revenues. The objective of an ex-ante regulatory test is that the regulator “approves” an investment – and associated costs – before the investment is made. This shall make regulatory ex-post reviews during the life time of the asset partly obsolete.

In many countries costs of capital are subject to extensive regulatory tests ex-ante including those for investment projects. The resulting costs provide the basis for the companies' regulated revenue. Regulatory tests ex ante can be used for an ex-post efficiency comparison by comparing the planned and the actual costs. This approach is very straightforward. Usually the TSOs propose expansion projects and turn to the regulator for approval. In exceptional cases, third parties may make the proposal.

From our country-related studies we have observed a broad variety of approaches ranging from very unspecific to quite sophisticated. A regulatory test can be implicit and simple or very comprehensive and sophisticated. If the test covers a wide set of economic criteria, including

external effects, and tries to quantify these criteria, we may speak of a social cost benefit analysis (SCBA).

A SCBA is an economic tool to assess the value of (investment) projects. The term ‘social’ implies the economic value for society, and relates to concepts known from economic theory, economic efficiency or social welfare. Strictly speaking, the assessment can be brought back to one number; if positive, the project is a good for society, if negative it is not. However, this is a naive interpretation of the SCBA. The method and therefore the outcome of a SCBA depend strongly on assumptions of future developments and therefore the outcome of a SCBA is in fact a discussion on the plausibility of the assumptions. This allows a substantiated debate on the underlying assumptions and a SCBA usually identifies very clearly the relative importance of assumptions.

In this section we will explain the main steps of a regulatory test and use Australia as its main example.

Australia developed a sophisticated regulatory test, which was subsequently adopted by New Zealand. Also, California uses quite sophisticated methods (TEAM). Within the context of the regulatory test, ex-ante it is useful to distinguish between “reliability investments” and “economic investments”, as those are regarded in different tests. After having approved a project by the regulator, the investment should enter the regulatory revenue base. This is the second step. In contrast, for instance Norway includes the investment as the second step into the benchmark. In such cases, it seems to be desirable (if not necessary) to rely on “lean” benchmarking only. Lean benchmarking implies that the network is taken as given. Thus the project as such is regarded as “used and useful”.

The following chapters provide an overview on the approaches chosen in:

- Australia
- New Zealand
- USA
- The Netherlands
- France
- Austria
- Norway
- Germany

3.3.2 AUSTRALIA

In Australia new significant infrastructure investment is subject to a detailed comprehensive prudence test, called the regulatory test.

The regulatory test is an analysis tool used by transmission and distribution businesses in the National Electricity Market (NEM) to assess the efficiency of network investment.” (AER, 2007, p. 4).¹³

The regulatory test is based on a cost-benefit analysis and adheres to the principles of economic efficiency and competitive neutrality. The test is a planning and consultative tool used to promote economically efficient investment in the electricity grid.

The test consists of two separate parts (“limbs”):

- The reliability limb and the
- market benefit limb.

The reliability limb states “that the option is necessitated principally by inability to meet the service standards linked to the technical requirements of schedule 5.1 of the NER or in applicable regulatory instruments.” Basically, these are the standard technical reliability requirements¹⁴.

The requirement to pass the reliability test is that the option minimizes the present value of the costs for meeting those requirements. Thus, for these types of investments, the aim is to minimize costs to achieve a predetermined target (in this case, network reliability standards)

The market benefits limb (AER, 2007, p. 54), following from NER clause 5.6.5A(b)(1) is based on a cost-benefit analysis. The social cost benefit analysis tries to capture the cost and benefit for society and not for the investor.

Benefits

The benefits are defined as (AER, 2007, p. 54/55): “Market benefit means the present value of the total benefit of an option (or an alternative option) to all those who produce, distribute and consume electricity in the National Electricity Market (NEM). In this context it has to be noted that the market benefit test will be passed if the option maximises the net economic benefit to all those who produce, consume and transport electricity in the market. Thus it is the best option chosen from a point of defined social welfare.”¹⁵

That is, the change in consumers’ plus producers’ surplus or another measure that can be demonstrated to produce

¹³ The current regulatory test is carried out by the Australian Energy Regulator (AER). Formal details are specified in the National Electricity Rules (NER; 2009, April, version 28):

¹⁴ Specified in NER 2009, schedule 5.1.A as system standards, and NER 2009, schedule 5.1.

¹⁵ Note the difference with the reliability test.

an equivalent ranking of options in a majority of reasonable scenarios.”

Costs

The AER (2007, p. 54/55) defines the costs of the option as: “The present value of the direct costs of an option (or an alternative option) including:

- Costs incurred in constructing or providing the option;
- Operating and maintenance costs over the operating life of the option; and
- Cost of complying with laws, regulations and applicable administrative requirements in relation to the option.¹⁶

Note that the cost-side in the test only covers the direct cost of constructing and operating the option. Other costs or avoided costs, like lower fuel costs as a result of more efficient dispatch or lower transmission losses do not belong to these costs but rather to the market benefits (positive or negative). The test does not aim to “maximize some hypothetical goal”, but instead it examines the proposed option as compared to a reasonable set of alternatives. If the set of alternatives is reasonably complete, then of course, we would implicitly approach maximization of social welfare.

Alternatives can include: (i) alternative network options, (ii) generation capacity, (iii) demand measures and (iv) doing nothing.

¹⁶ These costs are sometimes difficult to assess and are based on the regulators assessment, based on supporting studies by independent third parties and consultants.

The regulatory test (in Australia) requires the consideration of a detailed list of benefits, which does not fully coincide with the European view of an arm-length regulation. AER (2007, p. 54/55) lists the following (optional) benefits measured by their present value:

- Changes in fuel consumption arising through different generation dispatch;
- Changes in voluntary load curtailment;
- Changes in involuntary load shedding using a reasonable forecast of the value of electricity to consumers;
- Changes in costs caused through:
 - i. Differences in the timing of new plant;
 - ii. Differences in capital costs;
 - iii. Differences in the operational and maintenance costs; and
 - iv. Differences in the timing of transmission investments;
- Changes in transmission losses;
- Changes in ancillary services costs;
- Competition benefits being net changes in market benefit arising from the impact of the option on participant bidding behavior.

The most interesting point is the estimation of the competition effect. Broadly speaking the competition effect can also include less straightforward effects like improved liquidity on the various market places. New transmission capacity, especially if we think of interconnectors, will most often have effects on competition in production, trade and supply, positive or negative. The estimation of competition effects is typically the task of electricity market models. Interestingly, AER (2007, p. 54/55) states that a “pool dispatch model” should be used. The AER only gives indications of the requirements of such a model but

does not prescribe any model. Supply security shall be covered by the reliability limb. Implicitly it can be considered to be the expected cost of outages or congestion costs, which in turn is part of the definition of reliability. The test does not seem to include external/environmental effects, such as the costs of use of land, emissions of CO₂ and other pollutants, etc.

Changes to the regulatory test can be suggested by the national transmission planner (NTP), which forms part of the “Australian Energy Market Operator” (AEMO) a single, industry-funded national energy market operator. A slightly modified regulatory investment test for transmission, version 1, effectual from August 2010, features only very few changes compared to the current regulatory test version 3. The modifications suggested by NTP are subject to regulatory scrutiny.

The NTP will prepare a long-term strategic outlook (minimum 20 years), focusing on national transmission flow paths, the so-called NTNDP. This plan extends the current annual planning period for transmission systems of 10 years and thus will be more forward looking. The long-term strategic outlook is in addition to normal transmission-planning. Notably, it also planned that the NTP sets up a “database” on the assumptions methods and input data used in developing the NTNDP. This last part is very useful as it allows others to check calculations and progress on the models themselves. It effectively establishes something like an “open-source” long term transmission plan.

3.3.3 NEW ZEALAND

Grid expansion in New Zealand is subject to a regulatory test which is similar to the regulatory test in Australia. The overall regulatory approval package is called “Grid Upgrade Investment Review Policy (GRUIRP)”, and includes two separate tests called Grid Reliability Standard (GRS) and Grid Investment Test (GIT).

The GRS is an ‘economic’ grid reliability standard, consistent with the Grid Investment Test. The Grid Reliability Standard sets the minimum standard for the supply of electricity to any part of the grid. Investments required to meet this standard are known as ‘reliability’ investments. Other investments are ‘economic’ investments, where the benefits must exceed the costs: these include investments to relieve transmission constraints in order to reduce electricity generation costs. (Electricity Commission, 2008, p. 32). The GRS:

- Requires that reliability provided at any specific location is justified using a Value of Lost Load (VoLL).
- Enables a comparison to be made between alternative projects having different levels of reliability and capacity.
- Provides an interim n-1 safety for loads over 150MW.

According to item 5.3.17 of the GRUIRP 2008, the GIT is used to select a preferred option (the proposal) from a number of possible options (the alternatives). A proposal will satisfy the GIT if the Electricity Commission is reasonably satisfied that:

- For a proposed investment it is necessary to meet the reliability standard and that the investment maximises expected net market benefit or minimises the expected net market cost compared with a number of alternatives. Such a conclusion should be sufficiently robust having regard to the results of a sensitivity analysis; or
- For every other proposed investment it is necessary that the proposed investment maximises the expected net market benefit compared with a number of alternative projects; and the expected net market benefit is greater than zero and the conclusion above is sufficiently robust having regard to the results of the sensitivity analysis.

The objective of the GIT is to approve grid investment proposals when doing so maximises expected net market benefits to parties who produce, distribute, and consume electricity. These benefits comprise not just economic benefits (e.g. lower dispatch costs and competition benefits), but also reliability benefits and the benefits of certainty and acceptability (Electricity Commission, 2004, p. 1).

The GIT consists of three steps:

- First, market development scenarios associated with the proposed investment are identified.
- Second, the investment's net market benefits (benefits minus costs) within each scenario are estimated.
- Third, the expected net market benefit is calculated as a probability-weighted average of the scenario-specific net market benefits. A proposed investment satisfies the GIT if the Commission is reasonably satisfied that the investment's expected net market benefit is positive and exceeds the benefit offered by any feasible alternative investment.

The regulatory test in New Zealand tries to link reliability and the economic test (at least partly) as the economic criterion of the Value of Lost Load (VoLL) is used for the economic value of supply security for the end-users. The monetary value (instead of technical criteria like n-1) can then be combined with the appraisal of economic investments.

3.3.4 FERC – USA

Pursuant to the directives in section 1241 of the Energy Policy Act of 2005 FERC developed incentive-based rate treatments for transmission of electric energy in interstate commerce (i.e. cross border trade), on the basis of a new section 219 to Energy Policy Act of 2005.

By section 219 the Commission provides incentives for transmission infrastructure investment that will help ensure the reliability of the bulk power transmission system in the United States and reduce the cost of delivered power to customers by reducing transmission congestion. The incentives set reflect departures from what the Commission has permitted in the past and offers a greater flexibility with respect to the nature and timing of rate recovery for needed transmission infrastructure. In former years FERC has only permitted higher rates of return and deviations from past ratemaking practices in a few individual transmission infrastructure cases.

FERC has determined generically types of rate making options by the following incentive-based rate treatments:

- Incentive rates of return on equity for new investment by public utilities (both traditional utilities and stand-alone transmission companies, or transcos);
- Full recovery of prudently incurred construction work in progress;
- Full recovery of prudently incurred pre-operations costs;
- Full recovery of prudently incurred costs of abandoned facilities;
- Use of hypothetical capital structures, i.e. not the company's actual capital structure, but standard capital structures;
- Accumulated deferred income taxes for transcos;
- Adjustments to book value for transco sales/purchases;
- Accelerated depreciation;
- Deferred cost recovery for utilities with retail rate freezes; and

- A higher rate of return on equity for utilities that join and/or continue to be members of transmission organizations, such as (but not limited to) regional transmission organizations and independent system operators.

All rates approved under the rules are subject to Federal Power Act rate filing standards. The rule allows utilities on a case-by-case basis to select and justify the package of incentives needed to support new investment. Additionally, the rule provides expedited procedures for the approval of incentives to provide utilities greater regulatory certainty and facilitate the financing of projects. Recent cases exemplify the practice of the investment incentives by FERC:

- In December 2009 FERC granted Otter Tail Power Co.'s (Otter Tail) request for transmission infrastructure investment incentives related to its investment in three transmission projects that are part of Phase I of the CapX2020 Project.
- 100 percent of prudently incurred Construction Work in Progress in rate base; and
- 100 percent of prudently incurred costs of transmission facilities that are cancelled or abandoned for reasons beyond Otter Tail Power Co.'s control.
- In addition, the Commission accepted Otter Tail's proposal to recover its revenue requirement using a forward-looking formula rate under Attachment O-Otter Tail. The Commission conditioned its acceptance of Otter Tail's proposals upon Otter Tail submitting a compliance filing within 30 days that makes certain tariff revisions that are necessary to properly implement the requested incentives
- In January 2010 FERC granted Great River Energy's request for approval of various transmission infrastructure investment incentives related to its investment in three transmission projects that are part of Phase I of the Great River Energy's CapX2020 Project. Specifically, the Commission approved recovery of:
 - 100 percent of prudently incurred Construction Work in Progress in rate base and
 - 100 percent of prudently incurred costs of transmission facilities that are cancelled or abandoned for reasons beyond Great River Energy's control and
 - Hypothetical capital structure of 20 percent equity and 80 percent debt.
- In March 2010, FERC denies Baltimore Gas & Electric Company's request of rehearing the Commission's May 29, 2009 order authorizing transmission incentives pursuant to Order Nos. 679 and 679-A for BG&E portion of the 500 kV Mid-Atlantic Power Pathway (MAPP) Project. Specifically, the Commission authorized:
 - an return on equity (ROE) transmission rate adder of 150-basis points
 - an abandonment incentive (allows for 100 percent recovery of prudently incurred abandoned plant costs)
- In April 2010, FERC denies Public Service Electric and Gas Company's request of rehearing a prior Commission order for transmission incentives to PSE&G for construction of its portion of the Mid-Atlantic Power Pathway Project. Specifically, the Commission authorized:
 - a 150 basis-point return on equity adder

The US can be seen as a case-by-case regulation based on a common and flexible rule defining the range of investment incentives. The rule identifies specific incentives the Commission would allow based on a case-by-case analysis of individual transmission proposals. These incentives include uplifts to rate of return for TSOs – to encourage delivery of strategic investments. A TSO would receive

uplift to its normal regulated rate of return on the capital associated with the investment.

3.3.5 CALIFORNIA – USA

Quite similar to the regulatory test in Australia, the Californian Independent System Operator (ISO), CAISO, developed an investment expansion assessment method called TEAM, which is short for “Transmission Economic Assessment Methodology” (cf. CAISO; 2004). TEAM addresses five major enhancements:

- Utilizes a framework to consistently measure the benefits of a transmission expansion project to various participants. It provides policy makers with several options or perspectives on the distributional economic impacts of an expansion on consumers, producers, transmission owners or other entities entitled to congestion revenues, distinguishing congestion within and between regions
 - Utilizes a network model that can capture the physical constraints of the transmission grid as well as the economic impacts of a project
 - Provides a simulation method that incorporates the impact of strategic bidding on market prices. This allows the benefits of transmission expansions to be not limited solely to reducing the production cost of electricity but also to include consumer benefits due to reduced supplier market power
 - Addresses the uncertainty about future market conditions by providing a methodology for selecting a representative set of market scenarios to measure benefits of a transmission expansion and provides a methodology for assigning weighting factors (relative probabilities) to different scenarios so that the expected benefit and range of benefits for a transmission expansion can be determined
- Captures the interaction between generation, demand-side management, and transmission investment decisions recognizing that a transmission expansion can impact the profitability of new resources investment, so that a methodology should consider both the objectives of investors in resources (private profits) and the transmission planner (societal net-benefits)”

TEAM shows the desirable features of a regulatory test. The first point in the list above draws attention to economic efficiency as a main criterion and most notably to congestion as an indicator. For the latter feature a system with nodal or zonal prices is helpful and increases transparency. The second point explicitly mentions the use of a network model and related to point three (and actually also point five), which explicitly includes the competition effect.

3.3.6 THE NETHERLANDS

On December 3, 2004, the regulator DTe approved a high voltage direct current (HVDC) cable connecting the Netherlands and Norway, called NorNed, to be built and operated by TenneT (and Statnett in Norway).

NorNed is a 580km HVDC line; while it was originally planned to be 600 MW the approval has been given for 700 MW. The costs and benefits are split equally between Norway and the Netherlands. Art 6(6) of the EU Regulation on Cross-Border Exchange of July 1, 2004¹⁷ requires that revenues from the interconnectors should be used either for investment which increases the interconnector capacity, or be taken into consideration in rate regulation. This requirement has been translated in the Netherlands with art. 31(6) of the Electricity Act, which requires TenneT to re-invest the interconnection auction revenues to

¹⁷ Regulation 26 June 2003 (1228/2003) (1/7/04).

relieve interconnector scarcity. TenneT needs DTe's approval as the line was partly financed by the revenue fund from auction revenues from congested interconnectors (following the EU Regulation on cross-border exchanges, §6).

The regulator, DTe (now called "Energiekamer"), made an extensive regulatory test. The criteria used by DTe for the overall assessment are in particular the following (see DTe, 2004, p. 9):

- Consideration of the costs and revenues of the cable for TenneT and Dutch grid users;
- Value of the cable to the electricity market, including aspects such as liquidity, competition and the operation of market forces;
- Value of the cable with regard to security of supply;
- Effect of the cable on consumer and producer prices;
- Risks and the measures taken to manage risk;
- Opportunities for additional trade revenues through market coupling.

These criteria partly overlap and therefore, there is considerable risk of double counting.

3.3.7 FRANCE

In France for gas pipelines open seasons are not unusual. Significant new investments rely on a prudency test by the regulator CRE. The prudency test comprises two aspects:

- The test is implicit and relies strongly on bilateral negotiations between the regulator and the TSO. Justification of the bilateral negotiations rests on mutual trust, which is underpinned by the fact that the negotiations are one-to-one (instead of the including multi-

parties) and repetitive negotiations in a long-run setting where reputations matters.

CRE does not apply an explicit network model and the appraisal criteria are defined quite loosely. CRE's target is focused more on appropriate market design than to short term efficiency criteria. In the current approach, the TSO makes the investment proposal, after which the regulator (CRE) assesses the proposal.

The main criteria used by CRE for investment appraisal are:

- Long term network reliability
- Cross-border interconnectors
- Competition and non-discrimination

Basically this prudency test (for both gas and electricity) corresponds to an investment allowance with annual ex-ante assessment of investment plans. Investment expenditure goes into the regulatory asset base and thereby regulated network charges after approval.

The French system has investment uplifts in the Gas sector. Especially in the area of the long-distance gas pipelines with the two gas TSOs (GRTgaz und TIGF) for three reasons large investment needs are expected:

- Replacement of old assets
- Expansion of interconnector capacity
- Reduction of network congestion, resulting in a more competitive market and allowing a reduction of market (entry/exit) zones.

The current regulatory approach is cost-based (basically rate-of-return regulation) and efficiency incentives exist only in the background. For new investment the allowed rate of return is higher than for existing assets. Until recently, the investment top-up was 125 base points;

from 2009 onward the top-up is 300 base points and is valid for 10 years. CRE (2008, p. 84) states: „allocation of a 300 base point premium for 10 years, for all investments that create additional capacity on the main network or reduce the number of balancing zones..“.

- This approach is reminiscent of the approach by the US regulator FERC.

A rate-of-return top-up of 300 base points is high and presumably reflects the regulator’s fight for more competition by increasing capacity. A high uplift is able to promote network investment, but does little for least-cost investment or cost-reduction. The reliance on regulatory negotiations, whereby trust plays a key role has some elegance but is not without problems. First, the effectiveness will be impeded if multiple parties are involved. Second, there is a danger of regulatory capture. Third, the aims of objectivity and transparency are set in the background.

3.3.8 AUSTRIA

Transmission system operators (TSO) in Austria are subject to cost-based regulation. Article 31h of the Austrian Gaswirtschaftsgesetz (GWG), the law for operation of gas facilities, sets out that TSOs are obligated to grant access to the transmission system in return for a cost based and non-discriminating rate.

The methodology that is used to calculate the rates needs to be approved by E-Control, the Austrian regulator. The methodology shall refer to the cost basis, consisting of cost for capital, operation, own used gas, linepack management, maintenance, extension, administration and marketing. The return on equity (ROE) shall include an appropriate risk premium and shall be appropriate in an international comparison. Therefore E-control monitors whether planned investments with its cost included in the approved rate are executed. If not, the TSO might be

required to lower its rate. Costs for unplanned investments that maintain or enhance the usability of the system are included in the rate when the investment starts operation.

The last major cases where the Austrian regulator approved a specific rate determination methodology were:

- In 2007 the regulator approved the methodology of the Austrian TSO Salzburg AG für Energie, Verkehr und Telekommunikation for determination of its rates for the planned pipeline Tauern-Gasleitung (TGL). Start of operation shall be in 2012.
- In 2006 the methodology of the TSO Baumgarten-Oberkappel Gasleitungsgesellschaft m.b.H. (BOG) for determination of its rates for transportation services in the pipeline West-Austria-Gasleitung (WAG) were approved.

3.3.9 NORWAY

Norway also has a two-step procedure to deal with significant new investment. First, a prudency test (step 1) that checks whether the investments are used and useful (rather simple compared to Australia and New Zealand).¹⁸ After project approval (step 1), the investment is included in an international benchmarking. The benchmarking uses a refined DEA-model called ECOM+ (Efficiency of Construction, Operation and Maintenance). This model basically takes the network as given and analyses whether the investment was executed efficiently (step 2).

In the first step the regulator checks if the investment is used and useful, i.e. if the investment is required. In the

¹⁸ The investment planning of Nordel is based on the national investment plans which are regulated by the NRA.

second step, the regulator checks if the investment is efficient, i.e. if it is realized at minimum costs.

The Benchmarking model ECOM+ was developed for the Norwegian regulator NVE by Sumicsid¹⁹, in order to evaluate the efficient costs of the investment. ECOM+ can be called a “lean” benchmarking, because it explicitly takes the network as given. Agrell & Bogetoft (2006, p. 17) call their model: “a two inputs – OPEX and CAPEX - two outputs – SizeOfGridOPEX and SizeOfGridCAPEX technology model”. The model takes the (standardized) size of the network as the main output and assesses the cost level to provide this size of the network. ECOM+ is essentially a unit cost measure based on a standardized cost measure, both for capital cost and operating costs, divided by a normalized grid proxy constructed from a large number of asset items in 8 categories. Basically, ECOM+ uses a proxy for the network size or capacity as the output and the cost as the input.

This approach has two major advantages. First, although it can be done, there is wide agreement that an international TSO benchmarking implies problems and requires cautious interpretation. Differences between TSOs and between different countries are just enormous. The ECOM+ approach basically cuts out the problematic parts which are difficult to compare and concentrates on the parts that can be compared. Therefore, the impact of the benchmark is less severe and therefore the acceptance is higher.

Second, ECOM+ avoids a double prudency test and increases investors’ certainty. If projects are already approved as useful by the regulator, it would be contradictory if the same regulator somewhat later would

conclude by virtue of a full benchmarking that the investment was not useful after all.

3.3.10 GERMANY

In Germany, under the Incentive Regulation Ordinance, transmission system operators can apply for investment budgets for major projects, thus for an ex-ante approval of capital costs.

In accordance with the approval issued, transmission system operators will be able to adapt the revenue cap specified by the Federal Network Agency (BNetzA) as part of incentive regulation to the cost of capital incurred by the approved investment projects as from 1 January 2010. Please note that the capital costs are only approved until the start of the next regulatory period. From then onwards the capital costs are included in the entire regulated asset base of the network operator and subject to the regular regulatory review.

Operators of distribution networks can apply for investment budget only in case of integration of systems for the Renewable Energy Sources Act or the Combined Heat and Power Act relate, if thereby significant costs occur.

The application for investments has to include an analysis of the investment requirements. Those requirements are described in a guide for electricity respectively gas by six steps:

- Technical description of the project including timing and planned start.
- Proof of the necessity of the project.
- Explanation of the technical calculations made, proving the necessity of the project
- Economic assessment of the project including both capital and operating costs. For the proof of the costs

¹⁹ See for a detailed description, Agrell & Bogetoft (2006).

of the investment, network models can be applied or third parties can be asked for expertise.

- Analysis of feasible alternative projects to fulfill the extension needs. Additionally, the interaction with other planned and well-known investment projects have to be described.
- Detailed description of the selected alternative.

The application must also contain further information as appendices.

Receiving approval, the investment budget is defined as the costs of an investment plan. Basis for the allowable cost of capital is the sum of costs for the allowed investment measure. The investment budget should not include costs of investments that are already under the general revenue limit pursuant to § 4 (1) ARegV. Such costs are considered by approx. 60% of the sum of the depreciations of existing installations. The investments made minus this amount can be allowed as investment budget.

For the assessment of investments within a regulatory period a modified version of the ECOM+ is used. In the year 2009 the TSOs in Germany were subject to an international benchmarking called E3.

E3 is a follow up on ECOM+ developed by Sumicsid. E3 improves and extends in a couple of ways (cf. Sumicsid, 2009, p. 7): It has more than tripled the number of TSOs involved, relied on new and improved data definitions, covered a wider scope of activities and relaxed a series of assumptions about the underlying costs functions. Especially the model relaxes the assumptions of constant return to scale and includes cost drivers, contextual complexities like density and renewable energy.

E3 can also be seen as a “lean” benchmark as it takes the network as given. The E3-DEA-model uses three outputs:

- Normalized grid,
- Metric connection density and
- Capacity of connected power for renewable energy.

The second and third outputs are extensions as compared to ECOM+.

3.4 INCENTIVE MECHANISM

Previous chapters 3.2 and 3.3 discussed tools that indirectly imply incentive investments by providing a stable regulatory approach with positive impact on the project’s risk reduction. The following chapter now describes more direct investment incentives established in

- UK
- The Netherlands
- New Zealand

3.4.1 OVERVIEW

Different incentive systems are used for the purpose of motivating companies to remain below the approved cost level. Incentive systems can be introduced separately or combined with the ex-ante regulatory tests as described above. The incentives are usually provided to build new investments at minimum costs. The common mechanism is to set cost targets in the investment budget. The purpose of investment budgets is setting additional incentives to invest beyond the caps set within the incentive regulation. Investment budgets can also cover a single project regulated via separate cost review.

In the Netherlands and the UK different kinds of micro-incentives like sliding scales were used. Sliding scales are

profit sharing mechanisms, which reduces the regulatory risks for the regulated firm.²⁰

A further development of micro-incentives is the Menu of Sliding scales Regulation which can be seen as a mixture of incentive and rate of return regulation where the TSO can choose (on a so-called menu) between different slides which are more incentive based and slides which offer a more stable return on the capital employed.²¹

In the recent past, additional negotiated elements are introduced into incentive regulation. Negotiations are another approach where network user and network operators define specific conditions of trade. They are especially interesting in case of specific investments, for which general regulatory mechanism cannot be applied. Some jurisdictions provide the possibility of negotiations for "special investments".

3.4.2 SLIDING SCALE IN THE UK

3.4.2.1 COMMON SLIDING SCALE

The TSO in the UK energy markets is National Grid plc, which comprises the electricity TSO National Grid Electricity Transmission (NGET) and National Gas Grid (NGG), the gas TSO. These are fully unbundled transmission system operators, thus combining network ownership

(TO) and system operation (SO).²² Both NGET and NGG are subject to incentive regulation.

First we set out the characterization of the sliding scale approach for NGET. Second the incentive scheme for NGG is described. For the characterization of the sliding scale approach we concentrate on NGET, as the basic idea for NGG is similar. The sliding scales regulation does not only concern investments but is especially relevant in the context of financial incentives because it relies on the idea of risk sharing.

National Grid Electricity Transmission

National Grid Electricity Transmission (NGET) has two classes of network charges:

- Connection charges for the grid connection, and
- Use-of-System charges (UoS).

The latter can be subdivided into transmission network UoS charges (TNUoS) and Balancing System UoS charges (BSUoS)²³. The balancing service UoS charges cover losses and balancing services, where NGC is incentivized to reduce their costs by a sliding scale system.²⁴

The sliding scale consists of:

²⁰ For the evaluation of the experience see Hawdon, D.; Hunt, L, Levine, P and Rickman, N. (2005); OPTIMAL SLIDING SCALE REGULATION: AN APPLICATION TO REGIONALELECTRICITY DISTRIBUTION IN ENGLAND AND WALES, University of Surrey.

²¹ They were developed because optimal incentive schemes, designed to take account of information asymmetries, involve a menu of contracts that force the firm to surrender its private information. See Laffont, J.-J. / Tirole, J. (1993); A Theory of Incentives in Procurement and Regulation. MIT Press, Cambridge, Massachusetts.

²² There are small exceptions to the rule. For example NGET is an ISO in Scotland where the transmission networks belong to the Scottish utilities.

²³ TNUoS-Connection charges are only for costs directly associated with connection of a user at an entry/exit point of the grid.

²⁴ NGET's (or rather, the regulator, Ofgem's) approach is relatively shallow and relate mainly to the costs of assets which can be attributed directly to a user or a subset of users.

- Sharing (rules), i.e. rules that determine the allocation of the benefits gained from an investment between network operator and network users.
- Upper and lower limits (“caps and collars”) in recent years, and
- Deadband around the target reflecting increasing uncertainty about the target levels.

The following table gives an overview of the development of the scheme since its implementation in 2001 (current values applicable since April 2009 are not shown in the table). It has to be note that the target levels decreased first and then started to rise quite seriously. Moreover, we note that sliding scale factors decrease, suggesting a move towards a more cost-based approach.

£ m	Target	Sharing factors		Cap	Floor	Actual	Payment to/from NGET	Outturn Baseload Prices (£/MWh)
		Upside (%)	Downside (%)					
2001/02	382	40	12	46.3	-15.4	263.0	46.3	18
2002/03	367	60	50	60	-45	285.6	48.6	16
2003/04	340	50	50	40	-40	280.8	32.2	20
2004/05	320	40	40	40	-40	289.2	12.2	24
2005/06	378	40	20	40	-20	427.2	-4.0	42
2006/07	No scheme agreed					495.0	-	32
2007/08	430-445	20	20	10	10	451	-1.2	40
2008/09	530-545	25	25	15	15	827	-15	67
2009/10	571.43-601.43 ⁹	25	15	15	15	441 ¹⁰	15 ¹¹	

Table 1: NGET incentive mechanism (ofgem (2009) p. 12 (source:

<http://www.ofgem.gov.uk/Markets/WhlMkts/EffSystemOps/SystOplncent/Documents1/Final%20proposals%20consultation%20document.pdf>)

A target is set for each year and a sharing factor is defined for remaining below the target or exceeding the target. In the regulatory period 01/02, for example, the target was set at £ 382 million. In actual costs were £ 263 million. According to the sharing factor of 40%, NGET should receive an extra allowance of £ 47,6 million. However, the extra revenues are capped at £ 46,3 million,

which is the maximum extra revenues NGET may keep above the actual costs. It can be seen that the costs for UoS charges rose steeply from 2005 onwards, which led to extra costs for NEG.T.

The example shows the sliding scale mechanism applied for UoS charges. The sliding scale mechanism has also

been applied to investments recently. A strong advantage of a system like this, given that the system operator (SO) and the transmission owner (TO) are integrated (into one TSO), is that the TSO can trade-off possibilities to reduce balancing costs in operation and adjusting the network with upgrades and reinforcement.

Within the last years, NGET made some pressure to remove the incentive mechanism. Because it has become increasingly difficult to beat the target set. A rising level of congestion in the network, due to renewable generation led to National Grid to ask to abandon its SO congestion management incentive.²⁵

Ofgem intended to change the incentive scheme from the currently used annually incentives to a longer term incentive scheme for the regulation period beginning in April 2010. This was proposed against the background that annually schemes only incentivize sub-optimal to a longer term view of the system operation costs. Although NGET signaled support for the proposed development, Ofgem was concerned about its cost forecasting methodology. In particular Ofgem criticized, that market fundamentals, being key drivers of its cost are not considered enough. Instead the forecasting methodology relies heavily on historic data. Due to this poor forecasting methodology Ofgem stood back from its proposal of a multi-year incentive scheme.

The one year scheme that is chosen instead is set out below

Target	Deadband	Upside Sharing Factor	Downside Sharing Factor	Cap/Floor
£ 577.5 m	£ 550 m - £ 605 m	15%	15%	± £ 15 m

To enable the development of a multi-year scheme Ofgem proposes a new license condition which will require NGET to cooperate in reviewing its forecasting methodology's.

National Grid Gas

National Grid Gas (NGG) is the system operator for the gas National Transmission System in Great Britain. As system operator, NGG is responsible for residual balancing activities. With the following scheme NGG is financially incentivized to operate the system in the most economic and efficient way.

Currently there are seven unbundled gas schemes, shown in the table below:

Incentive	Performance Measure
Residual Balancing	Linepack and Price Measures
Demand Forecasting	Forecast error
Environmental	Volume of vented natural gas
Data Publication	Timeliness and Availability
Operating Margins	Cost
NTS Shrinkage	Cost
Unaccounted for Gas (UAG)	Absolute level of UAG

In the following these schemes are explained in more detail.

Residual Balancing

The Residual Balancing scheme consists of two interacting measures and is implemented for two years. The Price Performance Measure incentivizes NGG to minimize the impact of trades that it takes to balance supply and demand on the market. For the incentivizing period of 2009/2010 the target for impacts on the price due to balancing activities was 5%. This target is tightened to

²⁵ As this incentive is a major advantage of the integration of SO and TO (by creating a fat ISO) this raises questions about the advantages of continuing SO / TO integration.

2.5% for the incentivizing period of 2010/2011 and further tightened to 1.5% for the period of 2011/2012.

The Linepack Measure incentivizes NGG to ensure that the gas in the system (the linepack) at the end of each trading day is similar to that at the start of the gas day. The target is an allowed change of 2,8 m³. This target will be retained for the next two years.

The maximum profit or loss for the Residual Balancing scheme with its two measures is set at £ 2.4m.

Demand Forecasting

The Demand Forecasting Incentive is based on a comparison of NGGs day-ahead demand forecast and the outturn of that day. Around the forecasting target, an increase or a decrease in forecasting performance gives a profit or loss. The target for the absolute error of the incentivizing period 2010/2011 is 2.85%. Around this target, sharing factors of +/-15% in performance give a maximum profit or loss of £ 1.6m. The target for the incentivizing period 2011/2012 is 2.75%. Around this target, sharing factors of +/-25% in performance give a maximum profit or loss of £ 1.6 m.

Environmental

The Environmental Incentive ensures that the environmental costs of venting gas from compressors are factored into NGGs operational decisions. The valuation of carbon changed in the current period from the previous used shadow price of carbon to the non-traded carbon price. The target for the period of 2010/2011 is set to 3007 tons with a 10% deadband. The maximum profit or loss for an approximate 20% over or under performance is £ 0.6 m.

Data Publication

The Data Publication Incentive is based on a daily measure of NGG's performance compared to a benchmark. The Data Publication benchmark is based upon the availability and timeliness of the publication of certain data such as demand and flows onto the network. The target that is set for availability of certain data is 99.3%. The target for timeliness is 90.5% within 10 minutes. The maximum profit or loss for an over or under performance is set at £ 0.1 m.

Operating Margins

No Operating Margins scheme is proposed for the incentivizing period 2010/2011.

NTS Shrinkage

Shrinkage refers to gas that is either used to operate national transmission system compressors for system operation purposes or gas that is otherwise unbillable or unaccounted for by the measurement and allocation processes. The objective of the Shrinkage Incentive is for NGG to minimise the overall annual cost of shrinkage to the community. NGG can seek to minimise costs by reducing the volumes of shrinkage and/or efficiently procuring gas and electricity. The scheme that has been set for the incentivizing period of 2009/2010 and is valid for three years has an upside sharing factor of 25% and a downside sharing factor of 20% around the forecasted shrinkage costs of £150m. The maximum profit for NGG is £ 5 m. The maximum loss is £4m.

Unaccounted Amount of Gas

Unaccounted Amount of Gas (UAG) is the amount of gas that remains unaccounted in the system after all inputs and outputs are measured. Net positive unaccounted for

gas volumes have been gradually increasing in recent years, increasing necessary shrinkage payments. Therefore NGG is incentivized to reduce the amount of unaccounted gas in the system. The target for unaccounted gas is 2862 GWh. The maximum profit from over performing is £ 2 m.

3.4.2.2 MENU OF SLIDING SCALES

The newest development in regulatory practice is to try to overcome the informational asymmetry (between regulator and regulated firm), using incentive mechanisms. The UK regulator implemented an explicit incentive mechanism with the so-called menu of sliding scales. This is a variety of schemes with sliding scales elements or phrased differently bonus-malus factors (like being developed for instance in the Netherlands).

A next step is to make the regulated firms choose the sliding scale factor, which is known as a “menu of sliding scales”. The regulator designs a set of allowed revenues around different sharing factors; the firms then choose a sharing factor from this menu. If designed well, the firms will have an incentive to reveal the truth on their estimated costs.

With the correct scheme:

- Firm with investment requirement higher than expected by regulator will opt for cost-based regulation (high pass through factor)
- Firm with investment requirement lower than expected by regulator will opt for price-based regulation (low pass through factor)

Therefore, the system tries to balance between different incentives.²⁶

The menu regulation is applied only to predetermined uncertain investment blocks, especially investments to facilitate distributed generation, the so-called non-core building blocks. The other investment blocks, the core building blocks, that are relatively certain, are subject to straightforward ex ante investment budget. The core building blocks do include “general reinforcement costs”. Ofgem, (May 2009, p. 62) points out that the core building blocks cover 88 % of total investment expenditure and thus 12% remains for the non-core blocks. Ofgem (May 2009, p. 77) expects about £100 million network

²⁶ In the UK, price-cap regulation for the distribution networks (DNOs) started in 1990. For the fourth regulatory control period, which started 2005, a new element was added to the regulatory regime. The UK regulator, Ofgem, faced significant and uncertain investment requirements (for replacement and especially to facilitate DG) and faced the problem that different DNOs had strongly different views on how much new investment they needed. Ofgem (June 2004, p. 88) notes: “significant differences from the capex for DNOs”, and a severe lack of information thereof. The dilemma faced by Ofgem was to allow sufficiently high revenues so as not to frustrate necessary new investment, while at the same time not so high that regulation would become ineffective and inefficient. Hence, Ofgem wanted to allow a “CAPEX-pass-through” in case CAPEX-overspend (more than allowed by the investment budget) would be necessary and thus hesitated to use a strict price-based regulation. On the other hand, Ofgem wanted to avoid automatic cost-pass-through and thus hesitated to use strict cost-based regulation. The obvious solution thus is to find the middle way which is a “sliding scale”: A sliding scale is a mixture of price-based and cost-based regulation. The novelty introduced by Ofgem was not the sliding scale itself, but the “menu of sliding scales”, which is an “incentive mechanism”.

investment following about 9 GW DG connections in the next 5-year regulatory period.

The menu of sliding scales as introduced in 2005 is depicted in the table below:

DNO: PB Power Ratio	100	105	110	115	120	125	130	135	140
Efficiency Incentive	40%	38%	35%	33%	30%	28%	25%	23%	20%
Additional income	2.1	2.1	1.6	1.1	0.6	-0.1	-0.8	-1.6	-2.4
as pre-tax rate of return	0,200%	0,158%	0,130%	0,090%	0,046%	-0,004%	-0,062%	-0,124%	-0,192%
Rewards & Penalties									
Allowed expenditure	105	106.25	107.5	108.75	110	111.25	112.5	113.75	115
Actual Exp									
70	16.5	15.7	14.8	13.7	12.6	11.3	9.9	8.3	6.6
80	12.5	11.9	11.3	10.5	9.6	8.5	7.4	6.0	4.6
90	8.5	8.2	7.8	7.2	6.6	5.8	4.9	3.8	2.6
100	4.5	4.4	4.3	4.0	3.6	3.0	2.4	1.5	0.6
105	2.5	2.6	2.5	2.3	2.1	1.7	1.1	0.4	-0.4
110	0.5	0.7	0.8	0.7	0.6	0.3	-0.1	-0.7	-1.4
115	-1.5	-1.2	-1.0	-0.9	-0.9	-1.1	-1.4	-1.8	-2.4
120	-3.5	-3.1	-2.7	-2.5	-2.4	-2.5	-2.6	-3.0	-3.4
125	-5.5	-4.9	-4.5	-4.2	-3.9	-3.8	-3.9	-4.1	-4.4
130	-7.5	-6.8	-6.2	-5.8	-5.4	-5.2	-5.1	-5.2	-5.4
135	-9.5	-8.7	-8.0	-7.4	-6.9	-6.6	-6.4	-6.3	-6.4
140	-11.5	-10.6	-9.7	-9.0	-8.4	-8.0	-7.6	-7.5	-7.4

Table 2: Regulatory scheme for the electricity distribution networks in the UK (Ofgem, 2008; table 1, appendix 9, p. 110)

- The top line is the "Distribution Network Operator (DNO)/PB Power ratio". The DNOs request an investment budget for the upcoming regulatory period. This request is assessed by Ofgem (or more precisely Ofgem's consultants PB Power). The ratio of the requested sum by the DNO and the estimates of PB Power is the DNO-PB Power ratio. Therefore, a power ratio of 100 says that the expectations are the same. A power ratio of 120 expresses that the DNO requires 20% more than expected by Ofgem.
- The next step is that the DNO can change its request after learning the expectations of PB Power. Therefore, the DNOs have the final word and they thereby determine the power ratio. This is crucial. This system is a self-selecting, truth-revealing mechanism and therefore, the firms should have the choice.
- The second line is the efficiency incentive, which is the sliding-scale factor. The numbers are set by the regulator, while the firms choose one of the numbers. An efficiency incentive of for instance 40% means that 40% of capital overspend (the spending over and above the allowed budget) should be borne by the DNO and 60% can be passed through to end-users, and similar for capital underspend (spending less than the allowed budget): 40% means that 40% of capital underspend can be kept by the DNO while 60% must be passed through to the end-users. Note that to the left in the table, the efficiency incentive is relatively high which represents a price-based factor, and to the right in the table the efficiency incentive is relatively low which represents a cost-based factor.
- The third line is the "additional income", which are made-up numbers, without an intuitive explanation, but serve crucially to make the pay-off system in the

table "incentive compatible". The pay-offs in the table should be such that they do indeed set the incentive to tell the truth; this only works if the numbers are well-chosen.

- The fourth line represents allowed expenditure (CAPEX), which we denote as ALC. The numbers in the table are normalized to 100, although they do in fact represent real monetary values. The numbers for ALC are set by the regulator. Note that the values of ALC do not coincide with the requested budget of the DNOs. What is basically expressed is that if the power ratio is high, Ofgem is critical towards the requested investment needs, but is willing to give in a bit, while the sliding scale for capital overspend (should this happen) should take care of the rest.
- The lines at the bottom in the first column represent actual expenditure (CAPEX), which we denote with ACC. This is actual investment during the regulatory period. If ACC is higher than ALC, we call this capital overspend; if ACC is lower than ALC we call this capital underspend.
- Lastly, the numbers in the cells of the matrix are net profits and losses of the investments and reflect the penalties and rewards for capital overspend and underspend. A negative number means a lower rate of
- Whereas the table is designed by the regulator, the firms choose where in the table they will be, by choosing the column (basically by choosing the power ratio; all else follows from that).

The numbers in the cells are calculated as follows.

Total revenue is then calculated as:

$$R = ACC + \gamma + [(ALC - ACC) \cdot b]$$

which can be rewritten into:

$$R = b \cdot ALC + \gamma + (1 - b) \cdot ACC ,$$

Denote:

Efficiency incentive = b

Additional income = γ

Allowed CAPEX = ALC

Actual CAPEX = ACC

This exactly illustrates the sliding scale, as a weighted average of price-based regulation (ALC) and cost-based regulation (ACC). The shift factor is the marginal incentive, b . Profit or loss is defined as R , which gives the numbers in the cells.

Truth-telling-incentive of a menu

The truth-telling incentive can be exemplified by a DNO which has the same costs as assumed by Ofgem. Thus, the power ratio is 100 and if actual CAPEX is 100, total profit will be 4.5. It can be seen if the DNO has chosen 105, the total profits with cost of 100 would have been lower (4.4). For a second check we assume the true estimated investment costs to be 120, but Ofgem mistakenly believes it to be 100. In this case, the power ratio is 120, and if it actually spends 120, then actual CAPEX is 120 as well. Profits in this case are -2.4. That profit is negative and reflects the fact that the DNO's projections are above Ofgem's. Again, with cost of 120 there is no more favorable alternative shown by the fact the -2,4 is the most favorable outcome with a power ratio of 120,²⁷ as the

²⁷ Suppose for example that the DNO would rather adjust to the beliefs of Ofgem and adjust to 100, but as 120 was assumed to be the actual investment needs, we assume that actual CAPEX at

table is constructed such, the diagonal, where the ratio is equal to actual CAPEX is always the highest numbers on the horizontal line.

In addition there are incentives to spend less than expected, e.g. if the DNO may spend only 100. Then, the total profit would increase to 3.6, which is far better than – 2.4 but is less favorable as 4.5. Thus if the DSO would have assumed cost of 100 it would have chosen a power-ratio of 100.

- As a consequence, within the menu, truth-telling is the best or dominant strategy.
- The estimates of PB Power do not affect this decision – and by this the investment level - but they affect income, but not the investment decision. Thus, as the income is relevant the estimates of the experts should be designed like a “regulatory test” if possible.

Further, on the basis of estimated costs the DSO is incentivized to be efficient, e.g. to beat the estimated costs.

Assessment and recent results

For the assessment of the expected costs Ofgem uses a combination of analytical costs models and benchmarking. Thus, the individual power ratio and thereby normalized investment needs are at least partly derived from an industry average.²⁸ This favors more efficient firms. Nevertheless, it can be questioned if the total profit set is reasonable and sets incentives for a gaming. The DNO can

try to convince the regulator of a high investment requirement and high costs. If the regulator believes the high claim of the DNO, the ratio would be 100, and by mechanism the DNO would underspend. Consequently, it does pay-off to try to influence the regulator to be generous, implying that at least initially it does pay-off not to tell the truth. Further it has to be noticed that the attitude towards risk influences the outcome, as the answers rely on estimations of the needed capital. A risk-averse manager can respond to this by choosing a higher power ratio. A risk-averse manager may opt a power ratio 115 instead of a risk-neutral manager preferring 110. If actual CAPEX turns out to be 110, pay off will be 0.7 (which is less than 0.8), but if the actual CAPEX is indeed 115, pay off will be -0.9 (which is more than -1.0). If risk-averseness is sufficiently strong, we would observe this type of overestimation (“obtaining relatively cheap insurance”) and observe under spending.

Figure 2 summarizes the experiences in the UK. The vertical axis depicts the power ratio choices of the firms. It shows a shape similar to a half-normal distribution which is seen as a typical distribution of efficiencies in benchmarking, e.g. by stochastic frontier analysis (SFA) and MOLS. This suggests that the costs might be estimated by Ofgem in a right way. On the horizontal axes, the forecasted CAPEX compared to the allowed CAPEX. The figure further suggest that there is tendency towards CAPEX underspend. This might be explained by risk averseness.

120. Profits now decrease to – 3.5. Thus adjustment does not pay off and staying the truth-telling 120 would be better. This is not a coincidence.

²⁸ This can be seen a reason why menu regulation in the UK is used for DNOs but not for the TSOs, where the number of firms is too low to make a useful comparison.

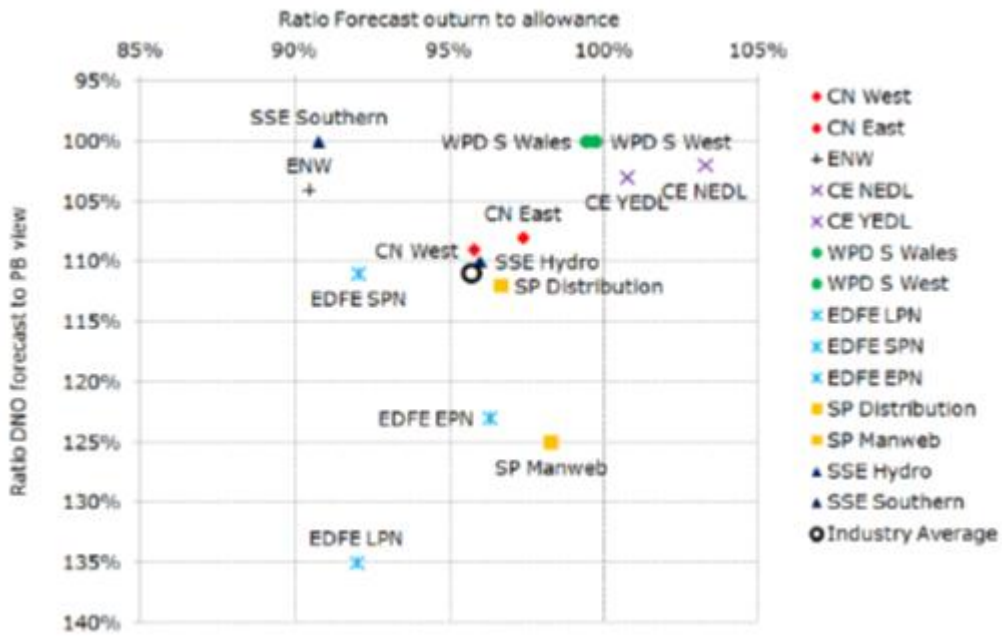


Figure 2: Ratio Forecast outturn to allowance (Ofgem, Dec 2008, p. 72)

3.4.3 BONUS-MALUS SYSTEM IN THE NETHERLANDS

A system of penalties and rewards has been used in the Netherlands in the context of NorNed, the DC-interconnector between the power transmission grids of the Netherlands and Norway, in somewhat different context of the timing of the investments and the capacity build. TenneT was incentivized by the following bonus-malus elements:

- The timing of finishing construction and starting operation (DTe, 2004, Rn 121)
- The capacity of the cable (DTe, 2004, Rn 106):
- The availability of the cable of 95.62% (DTe, 2004, Rn 112):
- Efficient construction (Dte, 2004, Rn 120):

It is interesting to note that these targets are similar to TenneT's own targets which was filled in the application. This may be useful information which can be used as a proxy for "truth-telling". Thus it can be assumed that the incentives of setting the target levels in the application are quite different as they are a kind of self-regulation and therefore might be less strict.

3.4.4 THE DPP/LPP MECHANISM IN NEW ZEALAND

In New Zealand the Commerce Act Part 4A demarcates the sector-specific regulation for certain sector (like the energy line companies) within the broader scope of competition law.²⁹ Under the Commerce Act part 4A, the DNOs can comply with a non-binding threshold value (which can be seen as a price- or revenue-cap), or breach

the threshold value and risk the intervention of the Commerce Commission. Uncertainty is created by the fact that the DNOs do not know what will happen in case of breaching. This uncertainty may frustrate investments as it is cost increasing. Since the ex-post adjustment by intervention is unclear, it is not obvious how much of breaching the threshold (over- or underspend) can be passed through.

In the Commerce Amendment Act 2008 changes of the regulation are introduced which try to reduce potentially frustrating uncertainty:

- The introduction of the optional scheme with a Default price path (DPP) vs. customized price path (CPP),
- More explicit formulation of the penalties and remedies, following the breach of the threshold.

In case the network operators face unexpected investment expenses and feel that the default price path (DPP) - the actual price path agreed on - does not suffice for this, they can apply for a customized price path (CPP). The CPP is in essence a cost-pass-through allowance.

DPP/ CPP regulation replaces the Part 4A thresholds regime. It is applied to electricity lines businesses that are not consumer-owned, and to gas pipelines. It requires the Commerce Commission to set a default price-quality path for regulated suppliers for (normally) 5 year periods. The start price may be existing prices or amended prices, with the rate of change in prices determined by the consumer price index less a requirement for productivity improvement, based on long run productivity improvement rates for the sector.

The Default Price Path (DPP) is a price-quality path (comparable to quality-adjusted RPI-X regulation).

²⁹ This construction is the result of the former light-handed regulation, which is considered to have failed.

- Starting prices are ending prices of the previous regulatory period, or based on current and projected profitability
- The path (basically RPI-X) comprises inflation and a general sector productivity trend (“total factor productivity” approach)
- Benchmarking is prohibited, thus the efficiency goals are all set by external factors

Suppliers may apply to the Commission for a customized price-quality path (CPP) if they have special requirements, such as significant new investment requirements at any time after the DPP is set. The Commission must make decisions on the proposal within approximately 12 months (MED, 2008, March).

Thus, the customized price path CPP is an ex-ante cost-based approach relying on own cost. It can be seen as an investment allowance tailored for the individual firm. The test of the CPP follows input methodology which is to be determined by the Commerce Commission till mid-2010. This test is a forward-looking building-block approach.

Thus the CPP is ex-ante cost-pass-through depending on the results, which can go in either way. Nothing guarantees that the allowed prices in CPP will be higher than under the DPP, although of course in the face of investment, this is likely.

The DPP/CPP mechanism is regarded skeptical by Green (2009): The process of lodging CPP proposals is seen as very “expensive and time consuming”.

The difficulties are:

- Putting together CPP proposal takes 1-2 years
- Proposals will be extremely lengthy documents

- The review will be time consuming and potentially expensive
- Risk of “sunk cost” if firm decides to retract CPP proposal in favor of DPP

By the optional mechanism the CPP serves as a risk-reducing safety valve and secures that necessary investments are not frustrated.

Nevertheless, the number of customized paths the Commission needs to consider each year is limited to four. If a DNO is not ‘in early’, it may end up with the default path for an additional two to three years, thereby delaying necessary investment or forcing the DNO to risk a breach.

3.4.5 INDIVIDUALISING OF THE INCENTIVE SCHEME

In the US and Canada we observe a development towards negotiated settlements where line investors negotiate conditions with the users. Users may be represented by consumer councils.

Negotiated settlements took root in the 60s in the USA. The Federal Power Commission had to solve thousands of rate cases. Realizing it would take decades to process all the cases the Commission encouraged the parties to settle with each other. Since then, most of the pipeline rate cases in the US were settled privately. The negotiated settlement saved time and reduced the uncertainty of the regulatory outcome. Another advantage of the negotiated settlements lies in the possibility to find innovative solutions for the involved parties. For example, in many cases the parties freeze the rates for a couple of years. Thus, more security is given to the customers and better efficiency incentives to the companies.

Canada has significant state involvement in its electricity sector and has drawn inspiration from the US in terms of its regulatory arrangements.³⁰ Further, Canada provides a good example of the use of negotiated settlements (see Doucet and Littlechild, 2006).

Since 1997, most of the rate cases in Canada are settled privately. Thus, the average regulatory processing time was reduced by 75%. These negotiated settlements include many features that go beyond the previous regulation, for example multi-year incentive arrangements, new provisions for service improvements or agreements on the provision of information.

Under this approach the pipeline company and its users negotiate a tariff settlement. This settlement covers the tariffs and its structure, the length of the contract and the quality standards and their monitoring. It will also propose the incentive mechanism for quality of service. The National Energy Board (NEB; www.neb.gc.ca) then evalu-

ates the settlement and decides whether to accept it or reject it.

It is important to note other likely developments in UK regulation. In particular there is considerable interest in the use of negotiated settlements in the electricity and gas sector. They seem to be likely a serious consideration within the UK's RPI-X@20 review. They have already been used in UK airport regulation where they are known as 'constructive engagement' (see Pollitt, 2008). The current Distribution Price Control Review process, which will set prices from 2010, notes that encouragement of more user engagement within regulation is wanted (see Ofgem, 2008).

Negotiated settlements are interesting against the background of disadvantages of the traditional utility regulation mostly due to asymmetric information, political reasons and specific differences in the rate cases to be solved in a pragmatic way.

³⁰ The context for Canadian regulation is similar to the US in that lawyers (rather than economists) are traditionally dominant within energy regulation. As in the US, companies have had to agree to incentive regulation rather than have it imposed upon them by legislation (as in Europe). The electricity sector is organised at the provincial level by state regulators. Natural gas transmission and oil pipelines (and international electricity transmission wires) are regulated by the National Energy Board of Canada (NEB). We focus on the experience of gas (and oil) transmission. The experience at the federal level is reflected in state level regulation of natural gas. Public ownership of electricity assets is significant and there are public and private gas companies. The degree of competition varies by province and by sector (electricity and gas). At the Federal Level the National Energy Board has to approve major oil and gas pipeline tariffs. It has gradually evolved towards a negotiated settlements approach.

- Firstly, it is questionable whether the regulator knows about the consumers' willingness to pay for such projects. Customers and their representatives can express their opinions, but normally they have no say in the final decision.
- The second disadvantage is that although there are variations in different companies and situations, it's always more or less the same approach of regulation. This is especially of concern in the stiff duration of the regulation period, which is the same for all companies.
- Another disadvantage is the devaluation of the relationship between customers and companies. In case of mandatory regulation, both can reach their goals more effectively by communicating with the regulator rather than among each other.

These disadvantages can be seen as regulatory failure. Negotiated settlements can contribute to degrade the regulatory failure if the bargaining positions are appropriate. The outcome of the negotiation is determined by the bargaining power of the involved parties and the information that is available for the consumers. Therefore it is necessary for the consumers to appoint an advocate (e.g. the Office of Public Council in most states of the USA, see above) to represent their interests. This advocate is more likely capable of gathering and processing the needed information and having a sufficient bargaining power with the great many of consumers that he represents. The regulator is still in place to ensure information disclosure and that parties comply with the negotiated settlement.

3.5 EXEMPTIONS FROM REGULATION

Exemptions from regulated third party access or regulatory network tariff setting and/or review can provide incentives for realization of, especially, projects with a high level of risk. The present chapter summarizes the exemption approaches applied in the US, Europe and Australia

3.5.1 US

Market-based incentives encourage a merchant investor or alternatively the existing TSO as a quasi-merchant investor to offer capacity beyond the baseline with less or even without regulation. Merchant investments are unregulated investments incentivized by market price differences.³¹ As a consequence these investments are exposed especially to the risks of parallel regulated or merchant investments. The risk of parallel regulated investments is higher because parallel merchant investments will rely on

³¹ At this point there is no general difference between gas and electricity.

the further existence of market price differences as well. This influence increases risks and therefore the costs of capital compared to regulated investments.

Merchant investors in the United States are not subject to special incentives like the regulated investments. Merchant projects are market driven while this final rule deals fundamentally with regulated transmission rates. True merchant transmission projects may play an important role in the future of transmission infrastructure development, but incentives related to, for example, return on equity (ROE) and cost recovery, do not apply to merchant transmission.

Nevertheless, merchant investments play a role in the context of regulated investments. This can be exemplified by the practice of PJM.³² PJM has a so-called deep-ISO model, which gives far-reaching investment decision competences to the ISO. Basically, the ISO PJM decides about reliability investments and can subsequently order the transmission owner to execute the investments; the investment costs then enters the Regulatory Asset Base and the network charges.

Due to the severe blackouts in recent times, in the US Reliability Investments have highest priority for the ISO. Under authority of the regulator FERC, the North American Electric Reliability Corporation (NERC) is responsible

³² The ISO PJM is responsible for the world's largest HV transmission network. Located at the US eastern coast it comprises the control areas in 13 US states and the District of Columbia and the associated markets for energy, reserve and balancing services and transmission rights. PJM is organized as a club and acts on behalf of its approx. 450 members. These members are all the relevant parties active in the PJM area; these include generators, transmission owners, distributors, traders, large end-users and consumer representatives and the regulator.

for determining the reliability criteria. Economic Investments are investments to reduce congestion.

- PJM collects data about congestion costs, which can provide an indication whether network expansion is useful. The indication is a simple test where the product of the expected flow and the price differences between two market areas under completely inelastic demand and supply curves is calculated. This unhedgeable congestion is considered as the social costs of congestion. If the unhedgeable congestion value attributed to a certain constraint over 12 months is higher than the costs of an upgrading, the benefit-cost-ratio is considered as positive.
- After Economic Investments have been identified there is a time window of one year within which merchant investors can submit proposals for the investment.
- If merchant investors do not successfully submit bids, the identified economic investments will be included in the investment plan and have to be executed by the responsible transmission owner.

This three-step procedure offers the possibility to attract private investors before regulated investment takes place. It takes account of two major drawbacks of unregulated merchant investors.

3.5.2 AUSTRALIA – MURRAYLINK

Murraylink is an unregulated 180 km long underground 220 MW DC line *MTI* connecting Victoria and South Australia. While Murraylink was under construction, the designated TSO Transgrid requested building of the regulated interconnector SNI between South Australia and New South Wales, which is largely parallel to Murraylink. SNI would decrease the price differential between Victoria and South Australia and thereby decrease the revenue base for Murraylink.

The test compared the so-called options bundled SNI and unbundled SNI. The latter would have upgraded the network in especially New South Wales without an additional line between the two areas. Cost benefit analysis suggested that the unbundled option resulted in a higher net benefit than the bundled option; i.e. upgrading the network in NSW and not building the line was more efficient than building the line given the existence of Murraylink.

The critical point of the unbundled SNI, as argued by Transgrid, was that network upgrading without building the line would leave the new investment vulnerable to market power of Murraylink. The authorised institution, NEMMCO, agreed and by lack of a better alternative the bundled option was approved and built. Subsequently, Murraylink requested conversion from unregulated to a regulated status which was granted in October 2003.

The Australian right of conversion is essentially a risk reducing provision but is rather unusual in a market setting but reacts to the danger of stranded cost as a merchant line may run into the problem that the project was the best alternative at the time of its building but is no longer economic because the situation has changed, e.g. the Murraylink investment after the building of SNI.

3.5.3 EUROPE

- Estonia-Finland: The Estlink case

In the EU merchant investors may, upon request, be exempted from the rules on third party access and/or those concerning the use of the collected congestion rents. These exemptions can only be granted by the 'national regulatory authority' on a case-by-case basis applying strict criteria. On 27 April 2005, the European Commission gave the green light to the Estlink submarine cable project connecting Estonia and Finland. Estlink is the first European merchant intercon-

connector, In February 2005 the Finnish Energy Market Authority and Estonian Ministry of Economic Affairs and Communications granted the request for exemption to Article 7 of the Regulation. Nordic Energy Link (NEL) has been granted an exemption from the general rules of TPA until the assets are transferred to the TSOs of Finland and Estonia, or the competent authority decides that circumstances have appeared that are in conflict with article 7 of the Regulation. The exemption lasts no longer than 31 December 2013. NEL holds auctions to sell rights to use the capacity that is available at any point in time and is unused by the Estlink owners themselves.³³

- Norway- Netherlands: NorNed cable

The NorNed cable forms a suitable example for both the merchant and regulated side of an investment. In 2003 a merchant initiative of realizing this DC-cable as interconnector between the Netherlands and Norway fizzled out. Statkraft and its Dutch counterpart NEA, had already signed exclusive deals to exchange power through the cable as the regulatory authorities were apparently likely to attach strict conditions (e.g. regarding TPA issues) to the merchant investment. Facing these conditions Statkraft and NEA did not proceed with the merchant project. It was taken over by the Dutch and Norwegian TSOs, TenneT and Statnett SF.

On 23 December 2004, the Dutch Office of Energy Regulation approved (after the approval of the Norwegian authorities) the construction of a 700 MW DC regulated interconnector.

This change shows that with TPA the possible rents of the projects were diminished as well as by the construction of a parallel interconnector exemplifying the vulnerability of private investments to market regulation. As a consequence the risks of private investments are much higher as regulated investments. These risks lead to higher capital costs of merchant investments due to a higher necessary return of capital employed.

- In the gas sector exemptions have been granted for the pipeline systems NABUCCO, the off-shore part of the Greece-Italy-Interconnector (IGI), the interconnector between the Netherlands and the UK (BBL), the German-Czech interconnector OPAL as well as for various LNG terminals (e.g. Grain, South Hook, Dragon (all UK), Livorno, Brindisi, Rovigo (all Italy), Lion-Gate, Eemshaven, Gate (all NL)).

3.6 TENDERING

3.6.1 OVERVIEW

Tendering can be seen as an instrument to set definite economic incentives, since a competition for an investment project is created. Public tendering is interesting in an economic sense because it offers the possibility to use additional (private) information given by the tendering procedure but it depends on an effective competition for investment projects.

An important question in the design of the tendering process ex-ante is the question who proposes the project. In some cases, initiating a tendered project can be decentralized and demand-driven (as for instance the UK off-shore cables). In other cases, especially within integrated projects within meshed networks, a centralized decision may be inevitable. Further the decision on the design of

³³ Furthermore, the use-it-or-lose-it principle applies.

the tendering project should not be chosen by an entity linked to any bidder.³⁴

3.6.2 ARGENTINA

The electricity sector consists of a competitive generation sector (the three state owned power companies were split into 27 generating companies), one major national transmission company (Transener), 6 sub-transmission companies and around 40 distribution companies since 2001. System operator is an ISO, CAMMESA, which is jointly owned by players in the industry. The generators are mostly privately owned. Electricity transmission is privately owned. Electricity distribution is in a mix of private -publicly ownership. All customers above a certain threshold size were free to switch supplier.

Transmission is ownership unbundled from the rest of the sector. At the national electricity sector level it is regulated by ENRE. ENRE is responsible for regulating electricity distribution only in Buenos Aires, state regulators are responsible for their own local distribution companies. ENARGAS is the regulatory agency responsible for gas.

A key feature of the new regulatory system was the regulation of the building of new transmission lines. Essentially Argentina operates a radial transmission network, bringing power from the south and west to Buenos Aires in the north. Argentina had three mechanisms for the determining where new investments could go ahead (see Littlechild, 2008, and Littlechild and Skerk, 2008).

- Contracts between the parties. When after negotiation between the regional sub-transmission company or a third party and the users of the line, 70% of the users agreed to cost the line could be built.
- Minor expansions. If the investment was less than \$2m the investments are in responsibility of Transener and costs may be passed to the users.
- A public contest method was used, PCM, explained below.

The Public Contest Method was an innovation. Under this method any party could propose that a new line would be built. An "area of influence" model then determines who (generators and distributors) benefits from the line and hence who should pay for it. Then the effected parties would vote on whether they wanted the new line. If more than 30% (weighted) of the beneficiaries voted against, the line would not go ahead. If the vote was in favour the line would be put out to tender. Littlechild (2008) evaluated the PCM as being a significant success for at least three reasons:

- First, it did prevent over-building of new lines for non-economic reasons, reducing politically motivated building of lines.
- Second, the tender auctions were a great success, attracting good numbers of bidders and significantly lower than expected prices.
- Third, there was a disciplining effect on the incumbent transmission company, who did win some of the tenders (but not all) by offering low prices.

The PCM is of course very appealing for the reasons mentioned above, but we do also think that there are limitations in the application for meshed networks. Allocating costs and benefits in a meshed network is a non-trivial matter, but does determine the outcome. Moreover, it

³⁴ The main interesting step would be to facilitate sufficient transparency to allow any party to put forth an investment project. The necessary alternative is that the designated TSO (or ISO) proposes necessary investment.

will be hard to deal with voting in case many users are involved.

3.6.3 OFFSHORE CABLES – UK

The large size of the investments, and their significance for total system costs (5-10%), has led the UK to propose an auction process for the installation of new offshore transmission lines.³⁵ Offshore generators shall apply for onshore connection rights of their wind parcs. Once they have secured rights onshore this triggers an auction process for offshore transmission operation. Ofgem runs the auction. There was considerable investor interest in the auctions to date, the first of which has taken place later in 2009.

The auction will be for the supply of transmission capacity to the wind parc for 20 years at a regulated price, creating Offshore Transmission Operators (OFTO). The regulated price will be equal to the amortised bid price (including operation) and be subject to a five yearly review by Ofgem. The regulated price will be for availability only and will not depend on actual energy flows. This reduces the regulatory risk with respect to cost compensation in case of a reduced loading of the lines and strengthens the incentive to increase the cable's availability. Wind parcs will pay charges in line with existing transmission charging methodologies. However OFTOs returns will be guaranteed regardless of energy flows and insured against abandonment risk.

The auctions will likely be for point-to-point connections from the wind parc directly to shore to be connected to the main network. The UK situation is such that an inter-

connected meshed offshore network seems unlikely to justify the costs. This is different from other European countries where an interconnected offshore cable system seems necessary. The difference is that the UK offshore wind parcs are spread along a long coastline and are located relatively near the coast. In Germany, they are located far away from the coast and located in bay-like areas in the northern North Sea and Baltic Sea. This implies that for a meshed network case it would be difficult to tender individual lines but instead it would be necessary to tender an entire offshore network which again requires central planning. Please note that this regulatory approach applies to the connection facilities of offshore wind parcs only and is different from the CAPEX regulation of the meshed onshore transmission network.

3.6.4 CAPACITY EXPANSION AGREEMENTS – UK

In the United Kingdom, with the NTS (National transmission system) exit reforms, a modified capacity booking and expansion agreement is introduced. This system shows some similarities with Open Seasons as well as with typical booking procedures as it is based on capacity agreement (including expansion agreements).

Exit points are predominantly connections to distribution networks, but include as well storage sites, direct connections to power stations, large industrial customers and other systems, such as interconnectors to other countries. Existing and new users of the NTS are able to purchase exit capacities for any NTS exit point.

The basic idea is, that existing system exit capacity shall be determined by network analysis undertaken at the

³⁵ The Offshore transmission auctions reflect the learning from the positive Argentine experience with auctions and with the use of the private finance initiative (PFI) for public services.

time of any valid request received by National Grid for NTS exit capacity.³⁶

The 'new' rules will apply to capacity being utilised from gas flow day 1 October 2012 onwards. The Exit reform implemented at 1 April 2009 is based especially on

- 4 years' user commitment for enduring flat capacities.
- Shippers book their own capacity at NTS Exit Points (in effect, DNOs book for DN shipper requirements).
- DNOs apply for Flat Capacity in Annual Application Window or ad hoc.
- Advanced Reservation of Capacity Agreements (AR-CAs) are for developers only.
- Starting with the year 2012 all capacities will be auctioned.
- Release of unallocated existing system exit capacity at NTS system exit points will be on a first come first served basis.

Beside the idea of booking capacities 4 years in advance the system of ARCAs is interesting.

ARCAs are agreements designed to protect TSOs against incurring costs in preparing for the connection of a large load that subsequently decides not to connect (e.g. abandonment of construction of a new CCGT). The risks associated with large loads connecting may be significantly higher than the average level of risk associated with a new connection to the system. ARCAs may only be requested where the developer is able to provide adequate evidence to demonstrate to National Grid's satisfaction

³⁶ In respect of NTS system exit points, such requests for NTS exit capacity shall be in accordance with the Uniform Network Code (TD Part IIC Paragraph 9).

that the requested capacity is genuinely required and is likely to be used from the date requested.³⁷

If an ARCA is requested and signed by the developer, National Grid will release the full amount of requested unallocated existing system exit capacity at the agreed release date. By an ARCA a "User Commitment" is applied which relates to the quantity of capacity reserved and the relevant NTS exit capacity price at the date of signature of the ARCA.³⁸

In Austria shippers or other customers who require extended capacities have to apply for the grid expansion at their responsible DNO. The costs that go along with the preparation of the additional capacity are charged from the customer via the singular grid-access-charge.

If the application for capacity expansion is denied by the DNO because of congestions in the upstream transmission system, the customers can apply for the respective expansions in the transmission system. The DNO is required to forward these applications to the responsible TSO. The TSO has to include these expansions in its long-term planning that needs approval by the regulator. If the long-term planning is approved by the regulator and the capacity expansion is covered by the approval, the TSO can contract with the DNO and the DNO can contract with the customer for capacity expansion. Within these contracts it is permitted to determine securities which the customer has to supply. In particular these securities are a defined payment from the customer in case he doesn't

³⁷ Such evidence could vary from project to project, but may include, for example, planning applications and "section 36" consents.

³⁸ Full details of the User Commitment will be specified in the ARCA.

use the capacity after preparation of the additional capacity in the full extent that was contracted.

3.7 OTHERS

3.7.1 OPEN SEASON

Tendering is in general attractive for gas investments if there is competition in the field of potential investors for transmission lines. Then, based on the planning of the transmission line the construction and operation can be auctioned to third parties.

For gas, open seasons are more common than tendering procedures as the extensions are normally planned by national TSOs. Open seasons formalize procedures where investment needs are identified by the TSO. They are based on the estimated cost by the TSO and the bids for the capacity registered shippers.

Open Seasons ERGEG published its Guidelines for Good Practice on Open Season Procedures (GGPOS) in May 2007. It is pointed out that open seasons help facilitating energy security and development of competitive markets by enhancing the requirement of:

- availability of sufficient infrastructure,
- sold at conditions that fit the market's needs,
- accessible on a transparent and non-discriminatory basis.

In fact, open seasons allow a project sponsor to efficiently consult the market about its needs for infrastructure, the terms the market would like the infrastructure to be marketed and to allocate the resulting capacity on a transparent and non-discriminatory basis.

The GGPOS point out that open seasons are only applicable if an appropriate congestion management to solve contractual congestion is deployed and there is substantial physical congestion.³⁹

Because a shipper's ability to use capacity on a given infrastructure is limited by the available downstream and upstream capacity the TSO must coordinate with adjacent TSOs to ensure compatible products in regard to timetables, processes and information provision. The structure of Open Seasons (OS) can be exemplified by the OS 2009 held in Denmark by Energinet.dk. The OS 2009 is based on the principles of the ERGEG Guidelines for Good Practice for Open Season.⁴⁰ Thus, in Denmark the OS 2009 consisted of a registration procedure and two subsequent phases under which it was possible to place bids for capacity.

▪ Registration

Any party who was interested in participating in the OS 2009 had to be registered with the TSO. Concrete conditions for such registration were defined for the shippers. If an interested participant was not registered as a shipper in the register of players, such shipper registration should be made in connection with the registration as an OS-participant. Registration for participation in OS was possible until 30 April 2009 at

³⁹ See as well: Commission staff working document on capacity allocation and congestion management for access to the natural gas transmission networks regulated under Article 5 of Regulation (EC) No 1775/2005 on conditions for access to the natural gas transmission networks, SEC(2007) 822 of 12 June (http://ec.europa.eu/energy/gas_electricity/interpretative_notes/doc/sec_2007_822.pdf)

⁴⁰ For more information on the ERGEG guidelines visit <http://www.energy-regulators.eu>.

11.30 a.m. (CET). All participants were subject to credit approval as well as the creditworthiness requirements.

- Phase 1

The purpose of Phase 1 is to conduct an - initial - analysis of the market needs for an expansion of the transmission system. A description of entry and exit points to/from the transmission system was included in the OS 2009. Possible capacity extensions and business cases were described. Furthermore, possible investment combinations were described.

The Phase 1 started at 10.00 a.m. (CET) on 30 January 2009 with the announcement of the open season procedure and consisted of:

- Submission of non-binding capacity bids by participants concerning OS

Participants were invited to place up to one long-term bid and one short- and medium-term bid per point per investment combination (i.e. up to 2 x 12 bids); and

- An analysis of the TSO of possible expansion scenario based on phase 1.

These bids were decisive for an investment combination and the participants to be qualified for Phase 2. Phase 1 bids were non-binding, but in Phase 2 they could be only varied up to +/- 15 per cent per point per investment combination compared to initial bids. Furthermore, the long-term bid might not exceed 70 per cent of the maximum technical capacity limit in a point and the aggregate Phase 1 bid in a point in each investment combination may not exceed 100 per cent of the maximum technical capacity limit.

Upon the Phase 1 bids the TSO undertook an initial analysis of expansion requirements and estimated the investments required. After the end of Phase 1 the TSO announced the aggregate amounts of capacity requested by participants at each point on its website. In a subsequent step the TSO announced the investment combination(s) being qualified for Phase 2 and invited the participants, who have placed a Phase 1 bid for the qualified investment combination(s), to submit a Phase 2 bid.

An investment combination was qualified for Phase 2 if either the economical capacity limit is met in all points in the relevant investment combination or the TSOs deemed that the investment combination should be qualified. Only participants, who have submitted a Phase 1 bid for the Investment Combination(s) were qualified for Phase 2. By this restriction participants were encouraged to place Phase 1 bids for all investment combinations relevant to them.

- Phase 2

Phase 2 commenced if one or more investment combinations were qualified in Phase 1. During Phase 2 the final decision regarding a possible expansion of the transmission system were made by the TSO based on new binding bids ("Phase 2 Bids") as well as on the TSOs analysis of the market needs.

The Phase 2 includes the following steps:

- Submission of Phase 2-bids.
- Allocation of OS 2009 capacity; and
- Entering into binding OS 2009 capacity agreements with the successful participants.

The deadline for the submission of Phase 2 bids expired at 11.30 a.m. (CET) on 7 September 2009.

The deadline for the submission of Phase 2 bids expired at 11.30 a.m. (CET) on 7 September 2009.

In case the aggregate amount of long-term capacity requested under the Phase 2 bids exceeds the economical capacity limit in all points in the relevant investment combination, the investment combination is qualified for expansion. If two or more investment combinations are qualified, it was at the TSOs sole discretion to decide on one investment combination to be finally qualified for expansion. By this rule, the participants were encouraged to place Phase 2 bids for all investment combinations relevant to them.

The TSO could add further capacity and investments to the investment combination finally chosen. Such additional capacity has to be made available under the terms and conditions of rules of the open seasons.

If the maximum technical capacity limit is not exceeded, all participants receive final and binding OS 2009 capacity agreements with the capacity requested in their Phase 2 bids in the investment combination qualified for expansion.

If the maximum technical capacity limit is exceeded, an alternative allocation mechanism will apply, whereby (i) Phase 2 bids regarding long-term capacity will have priority compared to Phase 2 bids regarding short- and medium-term capacity and (ii) Phase 2 bids will be reduced pro rata if such Phase 2 bids exceed the maximum technical capacity limit. If the maximum technical capacity limit is exceeded, the capacity agreements provided to the participants with pro rata reduced OS-capacity are deemed to be an offer to the participant regarding the amount of OS-capacity set

forth in the capacity agreement. Thus, the participant may reject to enter into the capacity agreement in which case this OS-capacity will be offered pro rata to the remaining participants. The TSO is not obliged to continue with the OS and the expansion of the transmission system if (i) the aggregate amount of capacity requested under Phase 2 falls below the economical capacity limit, either due to the lack of Phase 2 bids or participants having rejected allocated OS-capacity due to a pro rata reduction as a consequence of the maximum technical capacity limit being exceeded, or (ii) missing permits or approvals from public authorities or (iii) missing expansion plans in one or more adjacent systems which are required to execute the investment combination finally chosen for expansion.

3.7.2 AUCTION REVENUES

In addition to the full exemption from regulation, another approach shall also be discussed: The capture of congestion rents.

The regulation allows the network operators to earn market-based rates on a regulated asset, but sets certain conditions about the use of the revenues. The European Regulation No. 1228/2003 defines in Article 6 No. 6 that any revenues resulting from the auctioning of interconnection capacities shall be used for one or more of the following purposes:

- a) Guaranteeing the actual availability of the allocated capacity;
- b) Network investments maintaining or increasing interconnection capacities;
- c) As an income to be taken into account by regulatory authorities when approving the methodology for calculating network tariffs,

Comparable regulations are set by regulation no. 1775/2005 for natural gas networks as the transmission system operators shall implement and publish non-discriminatory and transparent capacity allocation mechanisms, which shall:

- a) Provide appropriate economic signals for efficient and maximum use of technical capacity and facilitate investment in new infrastructure;
- b) Be compatible with the market mechanisms including spot markets and trading hubs, while being flexible and capable of adapting to evolving market circumstances;
- c) Be compatible with the network access systems of the Member States.

These regulations influence tariff regulation by national regulators as they have to force TSOs to invest the congestion rents into new capacities or to deduct those rents from the approved network tariffs.

Thus, congestion rents are bound to alternative usage by European regulation. The alternative to invest in new capacities can be seen as some kind of negative incentive as otherwise the regulated income would be reduced.

In the Austrian gas regulation the negative incentive is part of the approved rate determination methodology. The methodology has to contain a stipulation that additional revenues, like the congestion rent, has to be either reinvested in the infrastructure, or to be given back to shippers and customers via reduced rates.

In Germany, as laid down in the ordinances on access to the electricity and gas grid (Stromnetzzugangsverordnung (NZV), Gasnetzzugangsverordnung (NZV)), the congestion rent or an additional revenue from auctioning congested capacities has either to be reinvested in order to relieve the congestion, or to be given back to shippers and customers via reduced rates.

4. EVALUATION OF INTERNATIONAL INVESTMENT INCENTIVE SYSTEMS

4.1 OVERVIEW

Table 3 provides a high-level overview to the experience gained.

Most of the countries have some form of investment plan in place. In Europe, where many different network operators operate a meshed network, a coordinated Ten Year Network Development Plan is required to enhance transparency and ensure that the need of the market is fully taken into account by the network operators – at least on transmission level.

Some form of ex-ante regulatory control is applied in most countries, even if they have a strong TOTEX incentive scheme⁴¹ in place. The ex-ante regulation is usually supported by some form of ex-post control to ensure that costs are kept low.

A direct incentive scheme for investments is applied in those countries, which have chosen for a separate regulation of operating expenditures and capital expenditures. The incentive systems are primarily focused on keeping the costs of the investments low, but do not necessarily encourage the investment per se.

The tendering procedure is used for specific investments in electricity and more commonly used for gas invest-

ments in Europe. It shall ensure that investments are made, if the market requires them.

4.2 (REGIONAL) INVESTMENT PLANS

A regional planning responsibility includes especially the economic and reliability evaluation of major regional investments. Reliability evaluations should be incorporated in the economic analysis.

- The economic analysis is a refined social-benefit analysis comparing different options. These options have to be described in details, especially the preferred one.
- A sensitivity analysis of the options to be preferred, like in the Nordic context, seems useful to evaluate the option by taking into account different reasonable developments in the future (scenarios).
- Major investments include interregional projects as well. An approach towards multinational investment projects is described below.

In every major investment process transparency and stakeholder participation is beneficial or even necessary.

A case of special interest can be seen in Open Season procedures used for investment planning in natural gas networks. Open Seasons are capacity commitments by the network users.

- Open Seasons are ruled by Guidelines of Good Practice.
- They consist of a three-step-procedure of gathering information on capacity needs and concrete capacity reservations based on bids of registered participants.

Open Seasons are useful for contracting parties for capacity enlargement and reducing the risks of the

⁴¹ Under the total cost or 'TOTEX' approach, the regulator does not differentiate between OPEX and CAPEX but sets the X-factor on the basis on the sum of these, i.e. on the basis of total cost (TO-TEX). In practical terms, this means that the regulator does not need to consider investment projections by the firm but instead it has to perform a benchmarking analysis of actually incurred levels of TOTEX. The resulting efficiency scores, then, form the basis for setting future allowed TOTEX levels.

operators. Additional capacity to the booked one can be offered by the TSO. Comparable commitment system, e.g. like the one used in the United Kingdom, for the exit reform are helpful too in stimulating investments because the risks on the side of the TSOs are

reduced by the booking in advance (by 4-years capacity auctions). At the same time Open Seasons make sure that the market is provided with the capacities needed for efficient cross border trade.

EVALUATION OF INTERNATIONAL INVESTMENT INCENTIVE SYSTEMS

	Regional Investment Plan	Regulated ex-ante tests	Incentives mechanisms	Tendering
UK	<input type="checkbox"/> Seven Year Statement	Ex-ante: <ul style="list-style-type: none"> <input type="checkbox"/> Planned costs are examined, and the regulatory authority makes its own appraisals as necessary. <input type="checkbox"/> Reimbursement on the basis of target costs. The target costs are planned costs that the company has chosen itself, in the framework of a "manual sliding scale". Ex-post: <ul style="list-style-type: none"> <input type="checkbox"/> Discrepancies between target values and actual values are subject to incentives mechanisms. No further efficiency reviews – for example, via CAPEX benchmarking – are carried out. 	<ul style="list-style-type: none"> <input type="checkbox"/> Incentives for remaining below target costs result from a "menu of sliding scales" procedure. <input type="checkbox"/> The network operator may choose a combination of target values and incentives. 	<input type="checkbox"/> An auction procedure for offshore cabling is being prepared.
Norway	<input type="checkbox"/> Nordic Investment Plan	Ex-ante: <ul style="list-style-type: none"> <input type="checkbox"/> Limited ex-ante check Ex-post: <ul style="list-style-type: none"> <input type="checkbox"/> Determination of a revenue cap on the basis of "structurally independent" benchmarking 	<input type="checkbox"/> Discrepancies between actual costs and the cap remain with the network operator	<input type="checkbox"/> n.a.
Netherlands	<input type="checkbox"/> Investment Plan <input type="checkbox"/> Contribution to European Ten Year Network Development Plan (TYNDP)	Ex-ante: <ul style="list-style-type: none"> <input type="checkbox"/> Costs of capital are determined via international benchmark. <input type="checkbox"/> Separate review of costs of capital solely for the NorNed cable Ex-post: <ul style="list-style-type: none"> <input type="checkbox"/> No further review of necessity (NorNed) takes place. 	<input type="checkbox"/> Departures from the target values are subject to a bonus-malus system (NorNed).	<input type="checkbox"/> n.a.
France	<input type="checkbox"/>	Ex-ante: <ul style="list-style-type: none"> <input type="checkbox"/> Cost-based regulatory review Ex-post: <ul style="list-style-type: none"> <input type="checkbox"/> Investment top-ups in connection with new investments 	<input type="checkbox"/> n.a	<input type="checkbox"/> n.a
Germany	<input type="checkbox"/> Contribution to TYNDP <input type="checkbox"/> Amendment to legislation planned to require long-term network development plan	Ex-ante: <ul style="list-style-type: none"> <input type="checkbox"/> Investment Budgets agreed based on actual costs Ex-post: <ul style="list-style-type: none"> <input type="checkbox"/> Consideration of all capital with in TOTEX-Benchmarking 	<input type="checkbox"/> Revenue cap regulation based on TOTEX-Benchmarking	<input type="checkbox"/> Open Season procedure in the gas industry
US	<input type="checkbox"/> Various solutions across US, no federal requirement <input type="checkbox"/> Investment Plans by PJM	Ex-ante: <ul style="list-style-type: none"> <input type="checkbox"/> Individually agreed parameters Ex-post: <ul style="list-style-type: none"> <input type="checkbox"/> Review of planned costs <input type="checkbox"/> Incentive elements 	<input type="checkbox"/> Incentive elements in form of bonus-malus based on building block approaches	<input type="checkbox"/> U.S.: Tendering primarily for trans-boundary connections of RTO/ISO; negotiation with Office of Public Counsel, which represents consumers <input type="checkbox"/> Canada: Negotiation used primarily in the gas sector; target returns and regulatory specifications are taken into account <input type="checkbox"/> Argentina: Public contest method; ROR
New Zealand		Ex-ante: <ul style="list-style-type: none"> <input type="checkbox"/> Regulatory review on the basis of GRUIRP <input type="checkbox"/> Revenue is determined in the framework of DPP and CPP. <input type="checkbox"/> The relevant method, which is currently being developed (completion planned for 2010), is based on a "building block" approach similar to that used in the UK. Ex-post: <ul style="list-style-type: none"> <input type="checkbox"/> Ex-post control via cost review in connection with determination of the next DPP and CPP limits <input type="checkbox"/> No CAPEX benchmarking 	<input type="checkbox"/> Incentives result from the possibility for actual costs to diverge from planned costs	<input type="checkbox"/> n.a.
Australia	<input type="checkbox"/> n.a.	Ex-ante: <ul style="list-style-type: none"> <input type="checkbox"/> Expansion investments are reviewed on the basis of regulatory tests. <input type="checkbox"/> Investments have to exceed a minimum threshold Ex-post: <ul style="list-style-type: none"> <input type="checkbox"/> Control comparable to that in the UK 	<input type="checkbox"/> Control comparable to that in the UK	<input type="checkbox"/> n.a.

Table 3: High level overview of international practice of investment regulation

4.3 REGULATORY EX-ANTE TESTS

Ex-ante approval of investment budgets (or more general: capital expenditures) is useful to reduce the risks of the investors. Such an ex-ante approval can be based on an investment planning and/or checked by the regulator by the means of network models. This ensures that the investment is in line with economic sound network extensions.

Proofs of the investment costs made are useful for major investments, especially if appropriate models are existent.

- In Germany for example, investment budgets and the planned costs can be checked by network models (to be developed);
- At the DSO-level there are no models in use or planned. This may point out the need of additional (micro) incentives, as such take into account incentives for cost reductions. Expert opinions may be an alternative solution for evaluation.

Network tariffs for existing and new investments should recognize the scarcities within the network. This leads to nodal or local pricing.

- These pricing can be seen as a so-called 'second best' approach to pricing. Second best pricing is welfare optimal pricing in case where first best pricing (according to marginal costs) is not possible. Such a pricing can be applied to electricity and gas networks.
- Local or nodal pricing is useful in the context of merchant investments as well because it sets the right incentives for unregulated private investments.⁴²

⁴² Brunekreeft, Neuhoff and Newbery (2004) point out that the nodal pricing approach allows a more refined merchant system

Side payments may accompany the network planning if the benefits accrue unilaterally and a regional or cross-border project is beneficial for all participants/stakeholders. The potential design of such side payments will be analysed in more details below.

4.4 INCENTIVE REGULATION

Micro incentives are useful to encourage higher investments especially within a regime of incentive regulation (RPI-X regulation). An incentive regulation without investment incentives is only useful in a static sense because traditional RPI-X regulation sets high incentives for cost reduction but will be suboptimal in a dynamic sense. The dynamic problems are generated by the fact that without appropriate incentives for quality and new investments the quality of the network may be deterred by low investment levels. Further, the needed extension/upgrade may be neglected if the costs are not covered and the expected rate-of-return is not high enough and/or the anticipated financial risks are too high.

Investment incentives are additional incentives to a quality regulation which does not exist in all countries and may be only effective with a time delay.

Investment incentives can be more or less refined:

- Rate-of-return adders like uplifts, tax deductions etc. are effective tools to set higher economic incentives. They should be set according to risks of an investment, e.g. the higher the risk the higher the rate-of-return adder or uplift. Such kinds of rate-of-return

with Financial Transmission Rights (FTRs) promoting better investment incentives.. It has to be taken into account that such a system of FTRs is complex and need a centralized allocation.

adders do not resolve the problem of asymmetric information and therefore can lead to informational rents of the regulated entities. They should be based on standardized costs.

More refined incentives like sliding scales or a Menu regulation are less common.

- Sliding scales are a possibility to set investment incentives as they offer a risk sharing for an investor. They can be used in combination with investment budgets or any other types of agreed aims to be set by a regulator. Based on the estimated costs sharing factors for higher and lower expenditures are defined which are capped as well. Depending on the sharing factors and the cost defined ex-ante, sliding scale arrangements may offer possibilities for additional incomes along with a reduction of risk.
- The Menu regulation is a combination of different sliding scales offering the possibility of self-selection for an investment project according to efficiency and risk-averseness of the investor. A risk-averse investor with limited efficiency may choose a sliding scale with a high percentage of cost covering in case of high unanticipated costs. A very efficient investor may choose a pure incentive scales with a low cost covering by the tariffs in case of high unanticipated costs. Like for sliding scales a sufficient knowledge by the regulator or third parties about the expected costs is necessary to define the right incentives.

A Menu regulation can be applied best if it is not intermingled with other incentive approaches like benchmarking of the investments made. It should be applied to separate cost basis.

The appropriate choice of micro incentives should depend on the regulator's knowledge of costs and risks. If the costs are rather uncertain, at least menu regulation will

not be appropriate because major parts of the incentives schemes cannot be defined and quantified properly. In such cases sliding scale might be used or rate-of-return adders might be favoured. On the other side the more refined incentives are useful if there is sufficient knowledge available.

For securing the efficiency of the network extensions the new infrastructure should be evaluated by a monitoring of the efficiency, e.g. by a lean benchmarking.

- A lean benchmarking is useful as well for all other major investment projects if they are regulated. Lean benchmarking ensures the efficiency of used and useful investments.
- The usefulness can be evaluated by the central investments planning process or by the TSOs.
- Exemptions from regulation and tendering

4.5 EXEMPTIONS FROM REGULATION AND TENDERING

Regulated investments can be accompanied by merchant investments or tendering procedures.

Merchant investments are unregulated investments. Such investments may be preferred, like in the PJM case, by a preferential time window where merchant investors can apply for beneficial investment projects. This will lead to a tendering procedure.

Tendering is attractive in addition (at least) for point-to-point connections like the UK wind farms. Tendering is attractive because it resolves the problem of asymmetric information if a fair competition between the bidders can be expected.

Merchant investments can be transformed into regulated investments as soon as the anticipated risks change in a relevant way. This limits the capital costs calculated by the private investors. If those risks are high (at the beginning of an investment) it seems useful to prefer a regulated approach.

Regulated investment can be planned after the time window for merchant investments or per se if preferred ex-ante. Regulated investments seem to be useful if the market risks in a region/country are high as they reduce the necessary returns on the capital employed. A tendering procedure for regulated investments is in general possible and could be cost-effective.

In any case, for the European case, the European Commission has developed the clear rule that, while balancing of interests on a case by case basis still necessary, exemptions need to be the ultima ratio⁴³. With open and regulated access to gas and electricity networks being the core of the European gas and electricity legislation, exemptions need to stay within the minimum limits necessary to allow realization of the project.

⁴³ Commission staff working document on Article 22 of Directive 2003/55/EC concerning common rules for the internal market in natural gas and Article 7 of Regulation (EC) No 1228/2003 on conditions for access to the network for cross-border exchanges in Electricity - New Infrastructure Exemptions; SEC(2009)642 final; http://ec.europa.eu/energy/gas_electricity/interpretative_notes/doc/sec_2009-642.pdf

5. FINDINGS ON THE STATUS QUO IN THE 8TH REGION AND IDENTIFICATION OF ROOM FOR IMPROVEMENT

5.1 OVERVIEW

In two recent reports the Energy Community Regulatory board (ECRB) investigated and assessed the investment regulation in the 8th region for the seven Contracting Parties of the Treaty establishing the Energy Community, namely Albania, Bosnia and Herzegovina, Croatia, FYR of Macedonia, Montenegro, Serbia and UNMIK⁴⁴:

- ECRB: “Cooperation of Regulators with regard to Cross-Border Investment Projects, March 10, 2010 and
- ECRB: “Regulatory Framework for the Development of the Energy Community Gas Ring”, March 10, 2010.

The first report assesses the possible future measures for improving regulatory promotion of new infrastructure projects. The results show that existing incentives are rather limited.

The main results were:

- Regulatory investment incentives for promotion of investments without Article 7 Regulation (EC) 1228/2003 (Article 17 Regulation (EC) 714/2009 – 3rd package) are only applied in FYR of Macedonia.

- Regulators do not have the power to recognize non-domestic investments in RAB.
- The tariff regime does not provide any specific tools for promoting investments.
- Regulators of the SEE region do not have harmonized responsibilities in relation to investment projects;
- Some regulators do not have power with regard to cross border transmission line investment plans at all;
- Cooperation of regulators regarding cross border transmission investments in SEE region so far is insignificant.

The reports provide a useful insight into the regulation of cross-border interconnection in the 8th region, but it does not provide sufficient information on the regulatory and statutory framework to evaluate the current investment incentive scheme implemented. Together with ECRB E-Bridge developed a questionnaire that has been distributed to all countries of the 8th region. The questionnaire has been answered for electricity and gas separately. An analysis of the responses received is provided in the following chapters.

5.2 INVESTMENT INCENTIVES IN ELECTRICITY

E-Bridge developed a questionnaire about the status quo of investment incentives in the different countries of the 8th region. This questionnaire has been discussed and approved by the Energy Community Regulatory Board and has been submitted to the various NRAs. The responses we received from the NRAs are summarized in Table 4:

⁴⁴ Moldova and Ukraine have not yet been Contracting Parties of the Energy Community at the date of finalization of the relevant reports and are therefore not mentioned as Contracting Parties.

	Albania	Bosnia and Herzegovina	Greece	Croatia	Hungary	UNMIK	Republic of Moldova	Slovenia	FYR of Macedonia	Montenegro
General Items	Incentive regulation implemented	-	n.a.	-	X	-	-	X	X	-
	Incentive regulation intended (in 2015)	X	n.a.	-	n.a.	X	-	n.a.	n.a.	X
	Quality regulation intended	X	n.a.	n.a.	X	X	X	n.a.	X	n.a.
	Ex-Post CAPEX disallowance	-	-	-	-	-	n.a.	X	-	X
	Other investment disincentives	-	-	-	-	X (no compensation of non-technical losses)	-	-	-	-
Regional Investment Plans	National Transmission System Investment Plan	X	X	X	X	X	X	X	X	X
	Approval required by NRA	X	X	X	X	X	X	X (by government)	X	X
Ex-Ante Tests	Ex-Ante approved investment budgets	X (not applied yet)	X	X	X	X	-	-	X	-
	Ex-Post monitoring of actual vs. planned costs	X (expert opinion, benchmarking)	n.a.	-	n.a.	X (expert opinion)	n.a.	n.a.	X (expert opinion)	n.a.
Micro Incentives	Higher rate-of-returns	-	X (not applied yet)	-	-	X (up to 3%)	-	-	-	-
	Any micro incentives in place	-	-	-	-	-	-	-	-	-
Exception from Regulation	Possible methods to monitor investment costs	X (expert opinion, benchmarking)	X (expert opinion)	n.a.	X (expert opinion, benchmarking)	X (expert opinion)	n.a.	X (benchmarking)	n.a.	X (expert opinion)
	Exemption from tariff regulation possible (if not a license service)	X	-	-	X (if supports market or increases SSS)	-	-	-	-	-
Others	Merchant investments	X (Albania - Italy)	-	-	-	-	-	-	n.a.	-
	Tendering in place	X (equipment)	X (equipment)	-	X (e.g. wind projects)	-	X (equipment)	X (equipment)	-	X (equipment)
	Capacity agreements in place, e.g. open season procedures	X (equipment)	-	X (not applied yet, planned for island connections)	n.a.	-	-	-	-	-

Table 4: Summary of the responses provided by the different NRAs in the 8th region with respect to investment incentives in electricity.

Please note that these responses have been provided by the NRAs of the 8th region. It is based on the individual interpretation of the questions of each authority.

- Incentive regulation in form of a **RPI-X regulation** has been implemented in Hungary, Slovenia and FY of Macedonia. Incentive regulation is envisaged to be implemented in the future in Albania, Bosnia and Herzegovina, UNMIK and Montenegro. Only Greece, Croatia and Moldova do not intend to introduce incentive regulation.
- Most of these countries also intend to introduce **quality regulation** in the future. Slovenia already introduced a quality regulation scheme. Quality regulation shall also be introduced in the Republic of Moldova, although incentive regulation shall not be implemented.
- However, although RPI-X regulation is or shall be introduced in most of the analyzed jurisdictions, only the NRAs in Slovenia and Montenegro expect disincentives for future investments by a potential ex-post disallowance of CAPEX. In Hungary and UNMIK, the non-compensation of non-technical losses may also introduce investment disincentives. In the UNMIK there is an additional cap on the network tariffs due to poverty level, which creates further disincentives for investments. Based on the responses received, all other NRAs do apparently not expect that the regulatory system provides disincentives for investments.
- **Investment Plans** are required in a number of countries. Network expansions are usually triggered by the TSOs in some cases also by governments and network users. The Plans need to be approved by the NRAs or the government. In Greece, the regulator provides the opinion to the Minister, who has the competence to approve a five year development plan. In FYR of Macedonia, it is pointed out that the regulator approves the investments in the transmission network. The regulator also approves the investments in the transmission network as well as the cross border investments. In Italy, the government proves the development plan, based on an informal opinion of the regulatory authority.
- The most common investment incentive mechanism currently applied by the NRAs in the investigated countries is the ex-ante approval of investment budgets. Investment budgets are, however, not used in the Republic of Moldova, Slovenia and Montenegro. The extra ex-post monitoring of the investment costs are usually done by making use by expert opinions. It is interesting that ex-post monitoring is not implemented in Croatia. No information has been provided by the Hungarian and Bosnia and Herzegovinian NRAs. Please note that some form of ex-post monitoring of investment budgets is always required independent on the precise realization of the investment budget.
- When investment budgets are common regulatory mean, the application of **higher rate of return** is not. Higher rate of return is only used in UNMIK and are capped at an additional 3%. They are also possible in Bosnia-Herzegovina and Greece, but have not been applied yet.
- Other **micro-incentives** have not been implemented yet. Also, the regulators in Albania, Bosnia and Herzegovina, Slovenia and Montenegro find micro-incentives not applicable. A sensible monitoring of investment costs is seen by the mean of expert opinions and/or benchmarking.
- **Exemption** from regulation is only regarded as a sensible regulatory tool in order to incentivize investments in Albania and Hungary. Merchant investors do only exist in Albania, so far for the interconnector between Albania and Italy. Exemptions are granted by the Albanian NRA only for non-license services. This allows a clear separation from the regulated.

- **Tendering** is currently only used by the Hungarian NRA, particularly with respect to wind projects. In UNMIK, tendering is used in the generating business, but not for networks. Irrespective of the tendering of a certain investment, the tendering for services is usually obligatory and is provided in all countries for services above a certain threshold.
- Capacity agreements are not used in electricity. Only the Greek NRA intends to make use of capacity agreements for the connections between the islands.

It can be concluded that the **most common investment incentives currently is the ex-ante proved investment budget**. The incentive results primarily from reducing the regulatory risks, namely the ex-ante disallowance of imputed capital costs. Other incentives, such as higher rate of return, exemptions from the regulations, micro-incentives or tendering are hardly used in electricity.

5.3 INVESTMENT INCENTIVES IN GAS

It is important to note that only Bosnia and Herzegovina, Croatia, FYR of Macedonia and Serbia are gasified. Further gasification is planned for Albania, Montenegro and UNMIK. However, the region is strategically positioned with respect to the new gas transportation projects which shall carry gas from the Caspian region, Russia and the Middle-East to the EU. An Energy Community Gas Ring shall be developed, linking the gas systems of the individual markets and considering both economies of scale and the realisation of non-domestic investments⁴⁵. The bene-

⁴⁵ Cross border projects typically to a certain extent exceed the infrastructure necessary for covering national demand. Reasonable and economically efficient transmission line planning, taking into account economies of scale, requires considering the capacity need necessary for transports through a Contracting Party for

fits from the strategic geographical location depends strongly on a development and progress of a concept that prudently recognizes the opportunities that can be gained from combining the various transmission, LNG and storage project with national investment plans of the various countries.

The “Energy Community Gas Ring” concept builds on the existing national investment plans from which expansion to a Ring concept is expected to develop gradually. The Energy Community Gas Ring is shown in figure 3:



Figure 3: Energy Community Gasring planned

The Energy Community Gas Ring shall connect all countries via a Ring considering the entire region. It will significantly contribute to the gasification within the region, but also provides benefits for upstream and downstream countries. In order to realize such Gas Ring, a minimum degree of regional coordination of the investment plans is necessary.

The responses received on the questionnaire on investment incentives in gas is provided in table 5.

covering demands of neighboring and further linked markets, so-called “non-domestic investments”.

	Albania	Greece	Croatia	Hungary	Italy	UNMIK	Slovenia	FYR of Macedonia	Serbia
Incentive regulation implemented	n.a.	-	-	X	X	-	X	X	-
Incentive regulation intended	n.a.	-	X (2011 for transmission)	n.a.	n.a.	X	n.a.	n.a.	X (probably 2013)
Quality regulation intended	n.a.	n.a.	X	n.a.	X	X	X	X	X
Ex-Post CAPEX disallowance	n.a.	-	-	-	X (only efficient costs)	-	-	-	X (only efficient costs)
Other investment disincentives	n.a.	n.a.	n.a.	X (no compensation of technical losses)	n.a.	X (no compensation of technical losses)	n.a.	n.a.	X (no compensation of technical losses)
National Transmission System Investment Plan	X	X	X	X	X	X	X	X	X
Approval required by NRA	X (and Government)	X (by Government)	X (by Government)	X	-	X	-	X	-
Ex-Ante approved investment budgets	n.a.	-	X (for TSOs)	X	-	X	-	X	X
Ex-Post monitoring of actual vs. planned costs	n.a.	n.a.	X (by expert opinion)	X (by expert opinion)	n.a.	X (by expert opinion)	n.a.	X (by expert opinion)	X (by expert opinion)
Higher rate-of-returns	n.a.	-	-	X (no legal support)	n.a.	X	-	-	- (restricted by tariffing)
Any micro-incentives in place	-	-	-	-	-	-	-	-	-
Possible methods to monitor investment costs	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.
Exemption from tariff regulation possible	n.a.	X (not applied)	X	X	X	-	X	-	-
Merchant investments	-	n.a.	-	-	X (Rovigo)	-	-	n.a.	-
Tendering in place	-	-	-	X (not applied yet)	-	-	-	-	-
Capacity agreements in place, e.g. open season procedures	-	-	-	X	X	-	X (pipeline to the individual end-user)	-	-

Table 5: Summary of the responses provided by the different NRAs in the 8th region with respect to investment incentives in gas

Please note that from the responses received the Albanian and UNMIK gas industries do not exist yet. However, both regulators have provided responses to some of the questions as the gas industries shall be developed in these countries. Also, respective gas legislation has already been developed.

- Incentive regulation in form of a **RPI-X regulation** has been implemented in four countries, namely in Hungary, Italy, Slovenia and FYR of Macedonia. Incentive regulation is envisaged in Croatia (at least for transmission) and in Serbia. All countries intend to introduce some form of quality regulation in the future. The Italian regulatory scheme already includes elements of quality regulation in its current form.
- Although RPI-X methods have or shall be implemented in most countries, only Italy and Serbia explicitly recognize investment disincentives, resulting from an ex-post disallowance of non-efficient capital costs. The NRAs in Hungary, UNMIK and Serbia fear that the non-compensation of technical losses may provide additional investment disincentives.
- The **need for network expansions** is usually identified by the TSOs, but may also be triggered by the government or market parties. The Investment Plans are usually approved by the NRAs or the governments. In Albania, the regulator has the duty to approve the licensees plan for each regulatory period, but no TSO has been established yet. In Croatia, the Five-Year-Development-Plan has to be approved by the Ministry, based on an opinion from the regulator. The system development plan is an integrated part of the approval process of the network tariffs. Approval is not required in Italy, Slovenia and Serbia. If approval is granted, the costs are considered in the Regulated Asset Base.

- In most of the countries, where an Investment Plan requires approval by the regulator or government, **investment budgets** have been introduced, which are **approved ex-ante**. Only the Greece Regulatory Authority does not use investment budgets, as an additional mean to incentive investments.

The Serbian Regulatory Authority uses ex-ante approved investment plans. The investment budgets are monitored ex-post by expert opinions.

- As ex-ante approved investment budgets are used to incentivize investments by the reduction of regulatory uncertainties, an explicit **increase of the regulated rate of return** is only possible in Hungary. The NRA in UNMIK intends to use higher rate of returns as well, but please note that the gas industry in this country has not been established yet. The introduction of a higher rate of return is not supported by the regulatory and/or legal framework in Croatia and Serbia.
- Additional **micro-incentives** to incentivize investment - such as bonus and malus schemes or the sliding scale approach, which determine how the benefits of cost savings are shared between network operators and network users - are not applied in any of these countries.

As with the introduction of higher rate of return, the current legal and/or regulatory framework may create an additional hurdle to implement micro-incentives in Croatia and Serbia.

Exemptions from regulations are possible in all countries other than FYR of Macedonia and Serbia. It is used to incentivize investments in case that the risk level of an investment in the regulatory regime would be too high. Once an investment is exempted from regulation, it shall not return to regulation again in

the future. The merchant investor has only been recognized in Italy yet.

Tendering as a possible mean to attract more incentives is not used in any of the analysed countries. Three regulatory authorities – Hungary, Italy and Slovenia – do use capacity agreements, such as open season, for identifying the investment needs and for concluding capacity contracts.

5.4 POSSIBLE ROOM FOR IMPROVEMENTS

It is interesting that only a few regulators see disincentives for investments in their regulatory environment. The disincentives, which have been identified, refer to

- Disincentives from potential disallowances of CAPEX in the future; and
- Reduced revenues from the non-recognition of losses; and
- Reduced revenues due to explicit caps on the network tariffs in order to consider a poverty level.

The latter course – the political consideration of a tariff cap – is clearly beyond the control of the network operator. It is fundamental that the network operator receives alternative funds in order to recover its costs. A social or political cap on tariffs, which does not allow the network operator to recover efficient investment costs, must be avoided.

With respect to the responses received we identified the following room for improvements:

- Clear identification of potential investment disincentives

From the reactions received, the need for further investment incentives did not become apparent in all jurisdictions. The analysis shall consider at least the following issues separately: a) do the network operators – or other parties – make all investments that are required? And b) are these investments made at minimum costs?

- Improve the coordination of a Regional Investment Plan

National Investment Plans exist for each country. In most of the cases it is required that these plans are approved by the regulators or governments. The development of an additional consistent Regional Investment Plan, which shall ensure that all required cross-border links are identified and considered in the National Development Plans, is required. Not only the development of such a plan needs to be coordinated, but also the approval process by regulators or governments.

- Design of the investment budgets

The mechanism of an investment budget is applied in most countries, but the methodology may need to be reviewed and further developed. Particularly, the application of investment budgets in a regulatory environment with an RPI-X based regulation is complex and difficult. The investment budget may either lead to a parallel accounting of assets underlying the RPI-X regulation and of assets, which are subject to the investment budget. Alternatively, the asset base of the investment budget may be transferred into the regulated asset base, which is subject to an ex-post control in the framework of the RPI-X regulation. Irrespective of what method is chosen, a transparent description of the investment budget is required, which is consistent with the rest of the regulatory approach. With

respect to cross-border links, investment budgets need to be harmonized among the involved NRAs.

- Improve incentives for efficiency

It seems that most regulators provide incentives by providing ex-ante approved investment budgets. This mechanism is effective as it encourages investments. However, it may not lead to the most economical solution. Only few regulators provide additional concepts by tendering or by micro-incentives. We rec-

commend using measures to improve the efficiency of investments carefully only if a minimum investment level is ensured and experience with incentive schemes have been gained by the regulator.

In the following chapter, we develop some recommendations for the Energy Community.

6. RECOMMENDATIONS FOR THE ENERGY COMMUNITY

6.1 OVERVIEW OF THE RECOMMENDATIONS FOR IMPROVEMENTS

As discussed above, the scope of incentives for investments is broad and may vary significantly among the countries. In order to better understand the need for improvement of investment incentives in each country, each NRA was asked to disclose the need of additional investment incentives in its own country.

As it has been analysed above, the regulation of investments vary significantly across the Energy Community. All NRAs have implemented some form of incentives for investments, of which the most common mean is the application of an investment budget.

Only few NRAs have identified explicit disincentives for investments in their country. The three main disincentives that have been recognized are:

- Disincentives from a potential ex-post disallowance of investment costs (Slovenia, Montenegro, Italy and Serbia); and
- Disincentives from the disapproval of cost coverage of non-technical losses (Hungary, UNMIK and Serbia) and

- The disincentives from a cap on the tariffs resulting from political poverty protection (Hungary, UNMIK and Serbia).

The first issue is certainly a regulatory issue, which results from the overall incentive regulation scheme- The second issue is a partly regulatory issue with respect to what extent the non-technical losses can be included in the allowed revenues. However, it is also a legislative issue as it affects the legal means to keep people responsible for actions like electricity theft and to inflict a consequential penalty. The last cause of a disincentive has only been identified by the Kosovo NRA and is a cap on the tariffs. This issue is beyond the control of a regulator and must be dealt with by legislative means.

Some form of investment incentives have been implemented in all countries. The applied measures vary and depend on the maturity of the regulatory system. However, all countries have implemented some form of investment plans and do apply some form of investment budgets. These forms of investment plans and investment budgets illustrates the strong emphasis that is put on the encouragement of investments rather than on efficiency improvements. This focus is fully supported by E-Bridge as it shall ensure sufficient investments. **We recommend to build on these existing regulatory investment incentive systems and to elaborate them further in order to introduce enhanced efficiency incentives.** The main recommendations for improvement of the investment incentives are provided in table 6.

Electricity	Albania	Bosnia and Herzegovina	Greece	Croatia	Hungary	UNMIK	Republic of Moldova	Slovenia	FYR of Macedonia	Montenegro
Identification and reduction of disincentives		Identificati of disincentives, if any		Consider revised solution for non-technical losses	Consider revised solution for non-technical losses	Consider revised solution for non-technical losses, provide alternative solution for poverty level	Identificati of disincentives, if any	Provide incentives to compensate ex-post CAPEX disallowance	Identificati of disincentives, if any	Provide incentives to compensate ex-post CAPEX disallowance
Improve (Regional) Investment Plans	Improve national investment plans by predefined evaluation criteria (socio-economic and security of supply) and encourage the development of an appropriate Regional Investment Plan by considering increasing obligations to cooperate. Develop coordinated approval process by NRSS.									
Enhance the use of Investment Budget	Review scope of the investment budget, the approval process and the term of the investment budget for potential improvement	Develop a clear approach towards monitoring of the investment budget and decide on the scope and term of the investment budget	Review scope of the investment budget, the approval process and the term of the investment budget for potential improvement	Develop a clear approach towards monitoring of the investment budget and decide on the scope and term of the investment budget	Review scope of the investment budget, the approval process and the term of the investment budget for potential improvement	Review scope of the investment budget, the approval process and the term of the investment budget for potential improvement	Consider the application of investment budgets, at least temporarily	Review scope of the investment budget, the approval process and the term of the investment budget for potential improvement	Consider the application of investment budgets, at least temporarily	
Natural Gas	Albania	Greece	Croatia	Hungary	Italy	UNMIK	Slovenia	FYR of Macedonia	Serbia	
Identification and reduction of disincentives	Identificati of disincentives, if any		Consider revised solution for non-technical losses	Provide incentives to compensate ex-post CAPEX disallowance	Provide incentives to compensate ex-post CAPEX disallowance	Consider revised solution for non-technical losses	Identificati of disincentives, if any		Provide incentives to compensate ex-post CAPEX disallowance; Consider revised solution for non-technical losses	
Improve (Regional) Investment Plans	Improve national investment plans by predefined evaluation criteria (socio-economic and security of supply) and encourage the development of an appropriate Regional Investment Plan by considering increasing obligations to cooperate. Develop coordinated approval process by NRSS.									
Enhance the use of Investment Budget	Consider the application of investment budgets, at least temporarily	Review scope of the investment budget, the approval process and the term of the investment budget for potential improvement	Review scope of the investment budget, the approval process and the term of the investment budget for potential improvement	Review scope of the investment budget, the approval process and the term of the investment budget for potential improvement	Consider the application of investment budgets, at least temporarily	Review scope of the investment budget, the approval process and the term of the investment budget for potential improvement	Consider the application of investment budgets, at least temporarily	Review scope of the investment budget, the approval process and the term of the investment budget for potential improvement	Consider the application of investment budgets, at least temporarily	

Table 6: Main areas for improvement of investment incentives in the electricity and gas industries in the 8th region

The recommendations can be structured into **four main areas**, which are described in greater detail below.

1. Review of the specific needs for additional investment incentives in each country and definition of the regulatory investment incentive intention.
2. Review of the political acceptance of the investment incentive intention
3. Elaboration of the national investment plans and assurance of consistency with regional investment plans in order to encourage sufficient investments
4. Elaboration of the investment budgets in order to introduce efficiency incentives.

The **first recommendation** is to carefully review the potential disincentives in the regulatory framework in each country. As described already above, only few NRAs identified disincentives for investments at all. A thorough analysis of the potential disincentives – or wrong means – is the basis of an effective investment incentive scheme. A careful analysis of investment incentives in each regulatory framework is required before implementing additional investment incentives shall be developed.

Secondly, the political acceptance needs to be reviewed carefully. Only the NRA in UNMIK indicated that a politically motivated cap of the tariffs creates an obstacle to investment. It is important that the legislative system supports the regulatory intentions sufficiently. Please refer to section 6.2 for further discussion.

Thirdly, we recommend establishing and improving the coordination of the investment plans among the TSOs. Any jurisdiction in the Energy Community requires the development of investment plans, but the need to coordinate the different national investment plans with the

regional investment plans – particularly with respect to investments in additional cross-border interconnection capacities – shall be improved.

Depending on what has been implemented in each country already, the focus should be laid on the obligation to cooperate, the cost sharing mechanism, the coordinated approval process, etc.

A (centralized) **investment planning is useful** because it ensures transparency and enables a public discussion on necessary investments. This increases the effectiveness of the planning process and facilitates the anticipation of market needs. Further, by approving the investment plans a stable outcome can be reached. The efficiency of the investment planning depends on the proper assessment of investment costs and the avoidance of asymmetric information between the regulated entity and the NRA.

Finally, a clear description of the **type and structure of the socio-economic benefit analysis needs to be specified**. This includes the potential investment in other networks or energy saving measures (smart metering or demand side management). This is discussed – together with some illustrative examples - in section 6.3.1.

There is also a need to **improve the investment budget in most countries**. Investment budgets are very complicated and must be integrated consistently into the entire regulatory framework. It has to be designed very differently in case, CAPEX are regulated as part of the total cost in a RPI-X regulation or are regulated separately in form of a building block approach. Special attention must be put on the scope and term of the investment budget, the ex-ante approval process, the ex-post monitoring process and other supplementary parameters. We develop and describe our recommendations in section 6.3.2

There are several additional and more advanced regulatory means available to provide specific investment incentives. Some NRAs apply these mechanisms already.

However, especially young regulatory authorities have to build up some reputation to decide fairly (i. e. their decision are accepted by a wide range of stakeholders) and in a timely manner. A good way to do so is by a **self-commitment to a rule-based policy**. This implies that **clear and accepted rules shall be developed**, including the unambiguous definition of:

- the intention and indication of using an investment incentive, e. g. by a social benefit analysis;
- the intended impact and effectiveness (and any other above-mentioned criteria) of an incentive mechanism in order to receive political support and transparency;
- the application procedure, including the setup of a social benefit analysis and the rules of cost application;
- the approval procedure, including methodology, time to approval, approval period and (if feasible) calculation of approved revenue / tariff add on;
- rules describing the treatment of the investments after the expiry of the regulatory period.

This report has described investment incentive mechanisms applied internationally and also provide an evaluation of the experience gained. **We recommend that these countries, who have not implemented the advanced mechanisms yet shall develop them only after the investment plans and the investment budgets have been developed further** and sufficient experience has been gained

6.2 LEGISLATION MEASURES

All NRAs have implemented some form of **investment plans and investment budgets** in order to encourage network operations to make the necessary investments. Some NRA provide additional regulatory means such as **exemptions from regulation or tendering**. From the an-

swers we received on the questionnaire there seem to be **no legal hurdles to implement** these additional regulatory mechanisms in those countries, who have not implemented them yet. We recommend reviewing the national laws and regulations to confirm this observation.

The NRA in UNMIK, however, indicated that a **cap on the tariffs**, which is applied in order to protect consumers who live in poverty, may provide a disincentive to invest. In other words, the tariffs, which would result from necessary investments, are socially and politically unacceptable. We recommend that **in case of socially unacceptable tariffs**, explicit subsidies are provided, either to the network user or to the network operator, to ensure that the investor, i.e. the network operator, can recover all its efficient costs.

A similar problem exists with the objection to compensate non-technical losses. Non-compensation of non-technical losses is an issue that has been intensively discussed in many jurisdictions. There may not be a single best solution to deal with this problem as it depends on the specific situation in each country. Mainly, the network operator argue that non-technical losses are beyond their control as they depend on social and cultural circumstances. The NRAs argue that it is mainly the network operator, who can manage and control non-technical losses.

A potential and pragmatic solution is to **provide some form of incentive system for non-technical losses, based on target values**. This approach allows the network operator to get a full compensation of its efficient costs, as long as the non-technical losses remain below the target value. Network operators are able to reduce non-technical losses below the target, they may keep some of the additional profits. Alternatively, in case they exceed the target level, they must carry part of the extra costs. The precise parameters of such an approach must be

developed with all involved stakeholders. See also the discussion of sliding scale in chapter 3

Political driven tariff caps that have no link with the network operator costs shall be abolished. In order to avoid any disincentives for investments, it is crucial that the network operators are compensated for the difference between its efficient costs and the revenues resulting from any potential tariff cap. The following rules may apply:

- The network operator must be able to receive a full compensation of its efficient costs. In case of investment budgets, micro-incentives, etc. it must be able to earn the full revenues as agreed by the regulator.
- In case of political driven tariff caps, the difference between the revenues from the tariffs and alternative compensations – e.g. social –economic subsidies – must be guaranteed.

It is important to note that any incentives for investments are significantly distorted by political measures that refrained the network operators from getting their efficient costs fully compensated.

6.3 REGULATORY MEANS

6.3.1 (REGIONAL) INVESTMENT PLANS

6.3.1.1 DRIVERS FOR INVESTMENTS – THE INVESTMENT NEED

Investments may be triggered by the intention

- to replace assets after the end of their life cycle,
- to increase capacities,
- to cope with additional energy demand / supply,

- to increase reliability of a network,
- and to enhance efficiency of the network (restructuring).

Not any kind of investment projects has to be promoted by incentive mechanisms. Network operators should be able to finance their replacements by operating cash flow. Direct payments as connection fees and construction subsidies should be preferred to the usage of investment incentive mechanisms, provided that a clear cost responsibility is proven and the free rider problem is kept under control. This is the case for e. g.

- connections and requested upgrades (especially when used exclusively by one customer)
- requested generator interconnections.

In return, TSOs / DSOs should be obliged to prove the connection demand in a certain time period (e. g. within two months). Refuses to connect or upgrade the applicant have to be substantiated. **In case of a refuse, the connection demand has to be considered for the (national) expansion plan.**

6.3.1.2 OBLIGATION TO OPERATE

Currently, several cross-border investment projects are planned on a discretionary basis between adjacent TSOs and prepared in joint project teams. Although discretionary (and especially bilateral) co-operation may be seen as a first step in the direction of regional network planning, some problems remain unsolved:

- Discretionary / bilateral planning may neglect preferences and / or negative effects of adjacent TSOs that are not involved in the planning procedure
- More efficient or more effective solutions may not be considered, if this would make the involvement of adjacent network operators necessary

Thus we recommend replacing discretionary co-operation by a rule based co-operation between the regulatory authorities and the network operators under the assistance of the Energy Community.

Having defined rules of regional co-operation, TSOs and national regulatory authorities commit to standard procedures for regional planning.

Formalized regional investment planning, as it has been proceeded in the Nordel co-operation and now in ENTSO-E and ENTSO-G, goes one step further. The objective of a formalized regional investment planning is to identify cross-border reinforcements and expansions which will be efficient from a regional perspective. Not only the effect of investments on selected countries (or smaller sections) will be investigated, but – as a result of a regional welfare maximization - for the whole region.

The result is the development of a grid master plan with proposals for cross-sectional grid reinforcements and expansions in the whole region.

We recommend concentrating on the development of basic rules for a co-operative investment planning covering the following issues.

- initiating cross-border projects
- approval of cross-border projects
- risk allocation
- cost sharing rules

Our recommendation is to **implement a rule-based co-operation where TSOs can trigger investment projects in other (!) countries of the Energy Community. A further step would be the implementation of a formalized regional investment planning**, as it has been introduced into the Nordic region successfully.

6.3.1.3 EVALUATION OF SOCIAL-ECONOMIC BENEFITS

▪ General approach

In most countries of the Energy Community the medium and long term network investment planning is initiated by the network operators and approved by the regulator. In some countries, the government approves the investment plans and in some countries the plan will not be approved at all. We cannot find strong evidence from the international analysis that one method would be superior to others. It seems to be more important, that investment planning procedures are rule-based and the compliance with these rules is transparent to the stakeholders (i. e. shippers, eligible and captive consumers, generators), in order to increase the public awareness of network planning. These requirements can be fulfilled by a combination of public consultation and social benefit analysis.

While we don't think that necessarily each investment project has to be evaluated in a welfare analysis, **we suggest that concerned stakeholders should be granted the right to call for** it provided that some projects have been discussed controversially during a public consultation. Notably, this could be either the case for projects that have been proposed or refused to implement by the TSO. The result of the cost benefit analysis has to be strictly binding, i. e., according to predefined criteria and the conceded result, the analyzed project than either has to be included into the network investment planning, or excluded.

The welfare analysis should consider at least:

- additional investment and operational costs induced by the project, regardless where they accrue, and
- social benefits from reduced / more efficient energy production, transportation and consumption, and an improved security of supply.

Strategic benefits, as from efficient market operation, market power mitigation, fuel diversity and the provision of emission reduction may be analyzed in a second step.

Any welfare analysis should include both the assessment for a “near future” point of time and an assessment of a medium term development. We propose to **define two or three different scenarios** for the medium term development, reflecting economic growth, development of energy resource prices and a potential participation at the carbon oxygen market. Alternatively, a sensitivity analysis could be useful to evaluate the preferred option.

For each scenario, a typical daily and seasonal load pattern and the associated production costs should be considered. Marginal production cost patterns of the particular regions will reflect the composition of the power generation mix. For instance, electricity markets with thermal dominated generation will face a clear peak load pricing structure, while the daily and seasonal price pattern will turn out to be less shaped under hydro dominated generation. Besides, the seasonal pattern will be intensified if electricity is used for heating.

The social benefit test shows a positive result (i. e. the project should be implemented), if the assessed social welfare gain exceeds the costs of the project. For the subsequent examples, we calculated the cost annuity for the investments, and compared them to the assessed annual welfare gain. The evaluation of the cost annuity is based on a 20-year investment horizon and an imputed annual interest rate of 10%.

Subsequently, we outline some sample analysis regarding topics that have been intensively discussed within the Energy Community.

- Example 1: macro-economic evaluation of network reliability

Bliem (2005) and De Nooj (2006) provide a simple macro-economic approach to measure the economic welfare of network reliability. This approach can be used for a cost benefit analysis of investment projects that increase the reliability of electricity and natural gas networks. Notably, reliability is particularly an electricity network issue, since interruptions of natural gas networks hardly appear.

The approach of Bliem (2005) and De Nooj (2006) is based on the assumption that in industrialized countries, energy – and especially electricity – is an important input for the production of goods and services and thus, energy rationing and power shortage will directly have a negative impact on gross domestic product (GDP). During electrical power outages, production declines significantly to a value close to zero, and in addition to that, every power outage causes some set-up costs, nearly irrespective of the duration of the interruption. Notably, the production loss caused by interruptions that have been announced in advance (planned interruptions) could turn out smaller, as producers and service providers may consider planned interruptions in their operational planning.

Keeping in mind that it is hardly possible to determine the exact value of lost output caused by an interruption, Bliem (2005) and De Nooj (2006) have chosen a pragmatic way to assess the welfare implications of electrical power outages by presuming a linear relationship between electricity consumption and GDP. Approximately, the value of lost load then can be calculated by dividing GDP by the annual energy consumption of non-residential (NR) customers:

$$VOLL_{NR}[EUR/kWh] = \frac{GDP [EUR/a]}{Energy\ Consumption_{NR} [kWh/a]}$$

Further, an approximate distinction of the value of lost load between sectors (e. g. industry, agriculture, services

and small business) is possible, regarding specific connection situations:

- Large industrial producers (IN) are mostly directly connected to the high voltage grid (65 kV and 110 kV). $VOLL_{IN}$ can be estimated by dividing the industry share of GDP by end consumption of high voltage customers.
- Services, transport and small businesses (SB) are usually connected to medium voltage (e. g. 6 kV, 10 kV, 20 kV, 35 kV) and low voltage grids. Therefore, $VOLL_{SB}$ can be estimated by dividing the value creation of services and small business by the end consumption of medium voltage and non-residential low voltage connections.
- Further, it can be assumed that agricultural (AG) value-added in large part is generated in rural areas. $VOLL_{AG}$ thus may be assessed by dividing agricultural value-added by end consumption of non-residential low voltage connections in rural areas.

Notably, the resulting VOLL-values vary significantly between the sectors, reversely reflecting the energy density

of the different sectors. In Germany, e. g., values range between 2.4 EUR / kWh for $VOLL_{IN}$ and $VOLL_{AG}$, and 12.1 EUR / kWh for $VOLL_{SB}$. For the Republic of Serbia, a rough estimation results in VOLL values between 0.9 EUR / kWh for the industrial sector and 2.8 EUR / kWh for the tertiary sector, based on estimated annual electricity consumption of 8 TWh p. a. for the industrial sector and of 5 TWh p. a. for the tertiary sector. The overall value of $VOLL_{NR}$ is about 2 EUR / kWh, and thus lower than in Central European countries (8 – 16 EUR / kWh), but comparable to other countries of the Energy Community (e. g. $VOLL_{NR}$ of 1.3 EUR / MWh for Macedonia, assuming an annual GDP of EUR 5Bn and a non-residential energy consumption of 2 TWh p. a.).

This broad variation of the values of lost load has to be considered, when cost benefit analyses of projects to increase network reliability are performed. In the course of the preparation of a cost benefit analysis, it has to be clarified which customer groups will benefit from an increased network reliability. To be more precise, the annual gross benefit of such a project can be calculated as for each voltage level.

$$\text{Gross benefit} \left[\frac{\text{EUR}}{\text{a}} \right]$$

$$= \text{Number of affected customers} \times \text{reduced SAIDI} \left[\frac{\text{h}}{\text{a}} \right] \times \text{average load per customer} [\text{kW}] \times \text{VOLL} \left[\frac{\text{EUR}}{\text{kWh}} \right]$$

The following example shall illustrate the proceeding:

Assume a sample economy with an annual GNP of EUR 10Bn (20% agriculture, 30% industrial, 50% ter-

tiary sector) and an electricity consumption of 10 TWh p. a. that is divided into

- 3 TWh annual consumption by 50 industrial producers connected to the high voltage grid, with an average consumption of 60 GWh p. a.
- 2 TWh annual consumption by 2000 large commercial and agricultural customers connected to the medium

voltage grid, with an average consumption of 1 GWh p. a.

- 1 TWh annual consumption by 50.000 small commercial and agricultural customers connected to the low voltage grid, with an average consumption of 20.000 kWh p. a.

Further, assume a SAIDI of 600 min / a [= 10 h / a] for the high voltage grid and a SAIDI of 1200 min / a [= 20 h / a] for the medium and low voltage grid.

Given these values, we receive the following values of lost load for industrial production and combined agricultural and commercial production:

- $VOLL_{IN} = 1.0 \text{ EUR / kWh}$
- $VOLL_{AG} / SB = 2.3 \text{ EUR / kWh}$

Thus, the average hourly costs per customer of an interruption varies between

- 6850 EUR / h for industrial customers connected to the high voltage grid,
- 263 EUR / h for large commercial / agricultural customers connected to the medium voltage grid,
- 5,25 EUR / h for small business and agricultural customers connected to the low voltage grid.

Note that although $VOLL_{IN}$ is lower than $VOLL_{AG}$ or $VOLL_{SB}$, an interruption of an industrial producer has a higher negative impact on social welfare than an interruption of a commercial customer, as the interrupted load is higher. This aspect should be recognized when analyzing the benefit of projects that should enhance network reliability. Thus, every voltage level should be analyzed separately.

Now suppose that an investment project proposes restructuring a high voltage radial distribution system, con-

necting 5 high voltage industrial customers directly and 250 medium voltage and 4000 low voltage commercial customers indirectly, by an (open) loop, which may reduce $SAIDI_{HV}$ for the connected high voltage customers from 600 min / a (close to) zero, and for the medium and low voltage customers from $SAIDI_{MV}$ or $SAIDI_{LV}$ from 1200 min or to 600 min / a, accordingly. In this case, the proper way to calculate the annual gross benefit from higher reliability would be:

$$\begin{aligned} \text{Gross benefit } \left[\frac{\text{EUR}}{\text{a}} \right] &= 5 \times 10 \left[\frac{\text{h}}{\text{a}} \right] \times 6850 [\text{kW}] \times 1.0 \left[\frac{\text{EUR}}{\text{kWh}} \right] \\ &+ 250 \times 10 \left[\frac{\text{h}}{\text{a}} \right] \times 114 [\text{kW}] \times 2.3 \left[\frac{\text{EUR}}{\text{kWh}} \right] \\ &+ 4000 \times 10 \left[\frac{\text{h}}{\text{a}} \right] \times 2.28 [\text{kW}] \times 2.3 \left[\frac{\text{EUR}}{\text{kWh}} \right] \end{aligned}$$

And as a result:

$$\begin{aligned} \text{Gross benefit } \left[\frac{\text{EUR}}{\text{a}} \right] &= 342,250 \left[\frac{\text{EUR}}{\text{a}} \right] + 655,500 \left[\frac{\text{EUR}}{\text{a}} \right] + 209,760 \left[\frac{\text{EUR}}{\text{a}} \right] \\ &= 1207,510 \left[\frac{\text{EUR}}{\text{a}} \right] \end{aligned}$$

Thus, the investment would generate a positive net benefit if the annuity of the investment cost does not exceed some EUR 1.2 m.

Notably, there are different reasons for an interruption of electricity supply. While in Central European countries, outages are mostly caused by failures in the technical equipment, inadequate supply apparently triggers peak load shedding in some member states of the Energy Community. It should be mentioned that these diverse causes call for different investment strategies:

- Replacement of assets and restructuring of the network is especially an option in case of failures caused by technical equipment (e. g. end of life cycle of assets)
- However, this is not a sufficient option in case of insufficient supply. Rather, investments in generation capacity and / or cross border capacity are necessary
- Demand management systems can be seen as a more intelligent way of load shedding, as they help allocate scarce electricity in a more efficient way. They can be supported by remote and / or smart metering systems. Although demand management appears relieving in the short run, it does not remediate existing supply insufficiencies and therefore doesn't have a lasting effect.

We thus recommend considering both short run and long run effects when conducting a cost benefit analysis of projects that should enhance network reliability.

- Example 2: Macro-economic evaluation of investments in different networks-

A large proportion of residential customers within the region of the Energy Community use electric energy for heating. It has often been stated that this heating technology is inefficient and a result of subsidized electricity prices for captive customers. Social benefit could be increased when residential customers substitute electric energy used for heating by other sources, in particular natural gas. We present a simple approach to test this hypothesis.

Note that provided residential electricity prices exceed the natural gas price but are lower than the regional electricity price, the positive net benefit of residential customers' gasification is quite obvious:

- Residential customers could benefit by switching from electricity heating to natural gas heating technology
- Power generators could benefit by selling electricity, which has been saved by residential customers, on the regional market and receive a higher price for it.

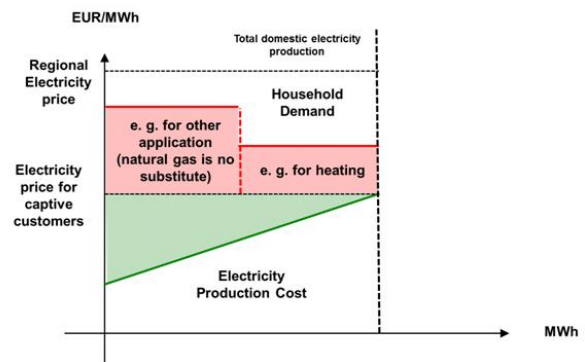


Figure 4: Initial situation – electricity is used for heating

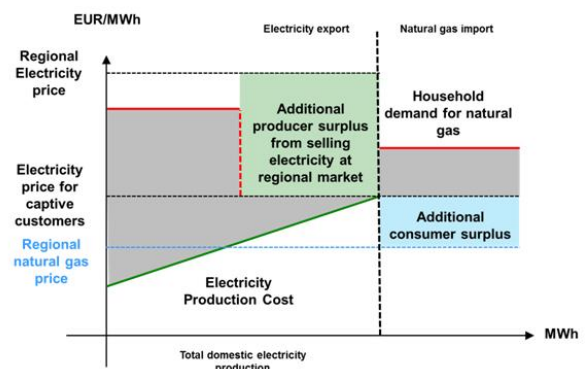


Figure 5: Electricity for heating has been substituted by natural gas consumption

Both the initial situation (assuming balanced foreign electricity trades) and potential benefits are illustrated in Figure 5 and Figure 6: In the initial situation, electricity is used for heating (with natural gas as a potential substitute) and for other issues (e. g. industrial demand, other household applications). When residential electricity demand for heating is substituted by natural gas, superfluous electricity can be sold on the regional market,

instead. Provided an initially balanced electricity trade position, this then will lead to an electricity export surplus. The overall gross welfare benefit of substituting electricity by natural gas heating technology corresponds to the price difference between the regional electricity and natural gas price, multiplied by the amount of substituted energy. For instance, with a price difference of 20 EUR / MWh (which is a rather conservative approximation) and an annual electricity consumption of 15 MWh for heating per household, the gross benefit would sum up to 300 EUR per household and year, or a total size of well above EUR 100 million p. a. throughout the Energy Community. This gross benefit has to cover infrastructure costs that go along with the gasification.

The general conclusion, i. e. that the price difference determines potential welfare gains, holds also true for the more realistic assumption that electricity prices – at least for captive residential customers – are massively subsidized, so that captive customers pay less for electricity than for natural gas. This is illustrated in Figure 7:

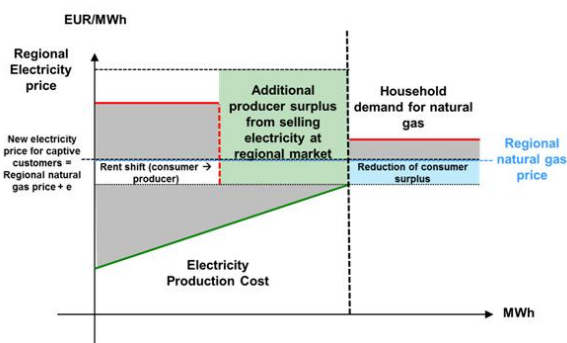


Figure 6: Distribution of social benefits of gasification

Yet, residential customers have to be offered an incentive to switch their heating technology. In Figure 7, it is assumed that this incentive is given by an increase of the electricity price of captive customers to at least the gas price level. Household customers will then have an incentive to use natural gas rather than electricity for heating,

and electricity producers may sell the generated electricity on the regional wholesale market. Provided that that a country has initially imported electricity to cover residential demand, gasification will effect in a decrease of electricity imports. In this case, gross benefits will correspond to the value of reduced energy imports, which again depends on the difference between the regional electricity and natural gas price.

Note that as an unintended, but inevitable side effect of an electricity price increase for captive customers, rents are shifted from residential customers to electricity producers.

The following example shall illustrate the proceeding:

Assume that a stylized country consists of 2.5 million households, where 25% of them, i. e. 625.000 in absolute figures, use electricity for heating. In average, these households demand an amount of 12.5 MWh p. a. of electricity for heating. Assume further a (regional) wholesale electricity price of 50 EUR / MWh, a regional natural gas price of 20 EUR / MWh and cost reflecting natural gas network tariffs of 15 EUR / MWh. Projects are planned with a 20 year time horizon and assuming 10% annual weighted cost of capital.

In this stylized country, having a single household switching its heating technology from electricity to natural gas would yield in annual energy cost savings of 375 EUR or a discounted value of nearly 3200 EUR over a time horizon of 20 years.

However, substantial investments are necessary to gain these cost savings. These investments cover in particular

- Construction of house connections. Unit costs are about 4000 EUR (Central European benchmark). Note, however, that effective costs per household are

much lower, since one apartment house may contain several flats.

- Construction / expansion of a natural gas distribution network and expansion of the transmission network. Cost annuity should be lower than the above-mentioned 15 EUR / MWh, considering economies of scale for construction and operation of distribution networks.
- Replacement of the heating plant (e. g. of heater by radiator). Note that these costs are born by the house owner, and may vary substantially. Notably, the opportunity costs (and not total costs) are decisive for the welfare analysis: Opportunity costs are (close to) zero, provided an old heating plant has to be replaced at the end of its life-cycle, and for new buildings. On the other hand, opportunity costs are high in case that a well working electricity heating plant is to be replaced.

6.3.2 NEGATIVE INCENTIVES

“Negative incentives” are the collective name of any regulation that obliges the TSO to use congestion revenues which are not re-invested for system expansion for tariff reduction. Notably, congestion revenues underestimate the welfare loss entailed by the respective congestion. Thus, an investment that is financed from these congestion rents, should be beneficial, if it reduces the congestion significantly.

Although the mechanism is simple, some rule-setting and regulatory monitoring is necessary. Experiences from European countries which have already implemented negative incentives, show that TSOs tend to use a bulk part of congestion revenues for the financing of national instead of cross-border projects. **Keeping in mind the situation of the Energy Community, where cross border projects are an important issue, we would suggest reserving a certain part of the congestion revenues for cross**

border investment projects. Further, **regulatory monitoring is necessary** in order to prevent TSOs from abusing congestion revenues for replacement investments.

6.3.3 MULTINATIONAL PROJECTS AND THE REGULATORY GAP

Special attention within this study is on resolving questions of facilitating and introducing regulatory incentives for infrastructure projects of regional (transnational) benefit. This is especially relevant against the background of the so-called “regulatory gap”.

A regulatory gap means that national regulatory authorities are not in the position to approve costs of the TSO’s infrastructure project of the regional dimension in the RAB, if they occur in a different jurisdiction.

Such cross-border investments have an influence on the benefits and costs of transmission in the countries interconnected. This is especially relevant in the gas sector because of the Energy Community Gas Ring concept.

Within the discussion of the Energy Community Gas Ring concept the following solutions are pointed out:

- Country by country financing of the investment costs
- Regional financing.

Only regional financing seems to be appropriate if the construction costs of important investment projects are interdependent on the countries demand and shall include possibilities to realize economies of scale and scope.

A cross-border interconnector can be beneficial in total but disadvantageous for some countries – or market parties - as prices in the low price country will increase and thus customers loose welfare in spite of potential gains of the producers which sell the energy to the high price country. Customers in transit countries might be

adversely influenced by higher network tariffs due to capacity extensions. A compensation mechanism may be required from the benefitting country to the other countries. Such compensation mechanism can be part of negotiations between the TSOs in the three countries. Thus, the TSO in the high price country may set compensation payments to the TSOs in the transit country and the low price country. Normally, these payments will only be based on the changes of TSOs income and costs and not on the benefits accruing to the customers. Therefore it has to be expected that the discussion on the level of TSOs will focus mainly on the allocation of costs of multinational projects.

Art 3 paragraph 6 Regulation (EC) No. 1228/2003 defines that the costs incurred as a result of hosting cross-border flows shall be established on the basis of the forward looking long-run average incremental costs, taking into account losses, investments in new infrastructure, and an appropriate proportion of the cost of existing infrastructure, as far as infrastructure is used for the transmission of cross-border flows, in particular taking into account the need to guarantee security of supply. This rule is the basis for the ITC-payments but it is not clear whether the ITC mechanism is able to allocate non-domestic costs to the beneficiary, especially if the ITC fund is capped. Thus, national regulatory authorities might be empowered to recognize extra-territorial costs to the RAB as far this is beneficial for the country or national customers (if the focus is put only on the customers side).

The ECRB (2010) therefore discusses three alternative solutions within this context:

- A first recommendation includes that TSOs shall be made responsible for developing investment plans which have to be approved by the national regulator.
- A second alternative could be the development of a model of appropriate costs allocation calculating the extra-territorial costs able to be recognized in the national RAB. Such an investment planning can be based on the 10-years planning of the TSOs to be coordinated by ENTSO-E and ENTSG.
- The third alternative is seen in the introduction of investment incentives, efficient congestion mechanism and capacity commitment agreements like Open Seasons.

Interregional investment planning can be based on national investment planning (bottom up-planning) or on a coordinated planning procedure (“More-or-less” top-down-planning). The **advantage of a coordinated planning is a higher efficiency** to be expected due to the goal of global optimisation in the region.

A coordinated planning can be disadvantageous from a national viewpoint if the national net benefits are smaller compared to best national planning. However, national planning may only identify a local, but not a global best solution.

These arguments are relevant in the context of **appropriate cost allocation of multi-national projects**. A method of cost allocation may rely in a first step only on the costs of network extension incurred by the national TSOs. This can limit cooperation within the network planning, if network extension is not a win-win-situation for every TSO or every country, e.g. if the benefits of higher capacities accrue to other countries. This raises the question of appropriate cost allocation between the TSOs.

The TSO in a benefitted country may cover the costs incurred in the countries not benefitting from network extensions. These costs can be recognized in his RAB. If the countries benefit to different degrees but all net benefits are positive there might be no need to compen-

sate other TSOs on a cost basis. Nevertheless, such a solution does not offer a direct approach to what extent extra-territorial costs have to be covered by the national RAB.

The following approach might be interesting for the allocations of costs:

- Allocation of the incremental costs of network extension according to the estimated benefits accruing to the countries within the next 10 years. For such an allocation a sound definition of benefits has to be set and agreed ex ante between the TSOs and national regulatory authorities. Useful is an approximation of the benefits by consumer rents and producer rents, as both parties are benefitting from trade. These rents can be calculated by simulations within a network model optimising the welfare between the countries connected.
- Remaining congestion rents will accrue to the TSOs. These rents should be used for lowering the tariffs (and thereby reducing the allocated costs as the tariffs are based on the RAB) or further network extensions.
- The results of Open Seasons might be useful for cost allocation too, as they indicate the shippers' interests and capacity booking. The capacity booking within Open Seasons is a proxy for the expected use and indicate the most useful network extensions. If the capacity bookings can be allocated to different destinations of entry and exit the potential flows can be approximated and used for cost allocations.
- Alternatively, a system of capacity agreements like in the UK might be used which shows relevant similarities with Open Seasons as the shippers' book capacity for a four years period. Additional capacities can be offered at the risk of the shippers by Advanced Reservation of Capacity Agreement (ARCA).

Cost allocation according to the distribution of benefits includes that the increase of the RAB is higher (or lower) than the costs directly incurred by the TSOs. Thus they can be seen as side payments too. Such an approach would connect investment planning

For limiting the costs of major network extensions it should be considered to tender the construction and operation. The approach of PJM is interesting in this case as it links unregulated and regulated alternatives. Unregulated investments would offer the additional possibility that the investor sets the appropriate prices by his own cost allocation. Regulated investments are favorable in the case of the cooperation of national TSOs.

The third alternative is described by different alternatives within the international analysis (uplifts and other rate-of-return-adders, menu-regulation, sliding scales etc.). It is favourable if these incentives should be coordinated within a region if they shall apply for multi-national projects.

If those (coordinated) micro incentives are sufficient to resolve the problem that a beneficial multi-national project may not be realized without recognizing extra-territorial costs, it may be appropriate to increase in harmonized way the incentives or to rely on recognizing extra-territorial costs in the RAB.

Efficient congestion management procedures like long term UIOLI and firm short-term UIOLI in gas on the basis of harmonized capacity products and market coupling approaches in electricity should be applied.

Congestion management procedures will reduce the need for network extensions or upgrades but do not generally resolve the problem of cost allocation of multi-national projects if such extensions still seem necessary.

6.4 INVESTMENT BUDGETS

6.4.1 SCOPE OF THE INVESTMENT BUDGET

Investment budgets are multi-annual cost approvals for specific investment projects (expansion and restructuring) for a specified period. For a certain time, the TSO is allowed to increase its revenue by a certain amount, which should cover additional capital costs, depreciation and operational costs that have been caused by the investment.

Dependent on the regulatory environment, investment budgets have the following effect:

- Within a regime of annual cost approvals, investment budgets reduce the uncertainty of future cash flows (i.e. uncertainty, if investment costs will be approved in the future). Uncertainty on future cash flows is a high regulatory risk and a serious obstacle to investments.
- Within a regime of multi annual regulation periods, investment budgets are necessary to recover increased costs of capital.

Under both circumstances, investment budgets will increase the willingness to invest into new infrastructure.

The following components should be considered for the calculation of the investment budget:

- Costs for planning and official applications
- Capital costs of assets under construction
- Imputed depreciation costs of finalized assets
- A lump sum for operational costs

On the other hand, the investment budget may be reduced by

- Governmental subsidies
- Construction subsidies from private / governmental investors
- Working capital (which can be seen as interest free debt)
- Any other kind of deductible capital

Notably, along with the finalization of the project, the financial structure of the involved capital as well as the total quantity will alter. This has to be taken into account when the amount of the investment budget is to be fixed, and we suggest adopting the annual budget scheme according to these forecasted variations.

6.4.2 TERM AND EXPIRY OF THE INVESTMENT BUDGET

A controversially discussed issue is the question of the term of an investment budget. In case of a building block approach, the capital costs are regulated separately from operating expenditures, investment budgets may be granted for the entire lifetime of the asset. It is obvious that the parameters of the investment budgets have to be harmonised with the parameters of the regulatory scheme of capital costs.

In regulatory systems, where the revenue cap is determined based on a RPI-X approach and the efficiency assessment is based on a TOTEX benchmarking, the application of investment budget is less straight forward. Usually, there are two fundamentally different options: a) granting investment budgets for the entire lifetime of the asset or b) granting an investment budget only temporarily until the asset is transferred into the entire regulated asset base.

A complete separate consideration of assets in an investment budget leads to two separate asset bases, one for the "normal" regulatory scheme, one for the investment

budget. These separate asset bases may lead to distorted incentives and may undermine the incentives provided by the regulatory scheme. We recommend approving investment budgets for the entire lifetime only in very special cases and circumstances, e.g. for the investment of special cable connections or converter stations.

In all other cases, we recommend granting investment budgets only as a temporary mean. The investments budgets shall ensure that significant investment costs are recovered for the period until the costs are considered in the regulated asset base – and subsequently in the increased revenue cap – at the next regulatory period. In case, the investment incentive shall be further increased, the term of the investment budget may be prolonged and covers the next regulating period(s).

After the expiry of the investment budget, assets will be transferred into the regulated asset base and treated like the other assets, i. e., their residual book value serves as basis for the calculation of imputed capital and depreciation costs, and thus has a direct impact on the allowed revenue cap that can be earned by the network operator, respectively.

The investment budget for specific project should be granted at least until end of the corresponding regulation period. However, in order to receive an effective investment incentive, a minimum approval period of 5 to 10 years should be granted. Thus, a prolongation of the investment budget into the subsequent regulation period(s) may be necessary.

Both regulatory authority and the applicant should commit to the compliance of distinct criteria. These criteria, e. g. the time schedule of a realization plan, reliability and other quality issues regarding the investment project, may be laid down in a bilateral agreement between applicant and regulator. Such an agreement may also grant not to

withdraw an approval even in the event of subsequent changes of the regulatory environment.

6.4.3 EX-ANTE APPROVAL

TSOs (or any other applicant) have to apply for an investment budget in advance. Therefore, the **applicant (e. g. TSO) should outline the necessity of the project.** In case of any doubts on the actual need, the regulator may test the necessity of the project (“used and useful-test”) by a social benefit analysis. This analysis should include:

- Cost comparison with alternative projects (suggested by both TSO and regulator with the same intention.
- Social benefit analysis including reliability and market issues. . The economic analysis is a refined social-benefit analysis comparing different options. These options have to be described in details, especially the preferred one. Note that the construction of a social welfare analysis has been outlined in section 6.4

Notably, in several EU countries (like in many other countries outside Europe), a detailed social benefit analysis of investment projects is not deemed as necessary. TSOs in these countries and regulatory authorities have a long lasting experience in the evaluation of network expansions, in these countries. However, the situation is different regarding the countries of the Energy Community. Hence, **we plea for a detailed social benefit analysis**, here, due to following reasons:

- Political feasibility: In order to earn the investment budget, the TSO has to increase tariffs. A social benefit analysis adds transparency and supports understanding for tariff increases.
- Tariff allocation: A social benefit analysis makes transparent which groups (e. g. household / commercial / industrial consumers; producers) benefit from specific investment projects. This information is a necessary

input for the development of a tariff adjustment where groups who benefit from specific investments are also predominantly charged.

- Scarcity of capital: In case of scarce capital, investment project should be prioritized, which have the highest rate of return (in terms of benefit per invested EUR). This can be calculated by a social benefit analysis. Further, if private / foreign capital has to be attracted, these investors may ask for a “business plan” even in a regulated environment.

Provided a rate-of-return regulation, replacement investments can usually be financed by the imputed depreciation of assets (as part of the capital costs that are covered by network tariffs). Hence, investment budgets are usually only assigned for network expansions.

As a consequence, any application for an investment budget has to disclose the replacement part from the expansion part of the investment project, first. Especially thinking about restructuring investments (e. g. replacement of a 220 kV lines by a 380 kV lines), the regulator has some interpretational freedom to accept the disclosure concept – and thus enable the TSO to apply an investment budget for the remaining investments, respectively, which are interpreted as network expansion. In a stable economic and regulatory environment, there will be investment incentives even under a “strict” setting (only additional costs from network extension are accepted as “expansion part” and therefore financed by an investment budget). Where this is not the case (for instance because original construction costs hardly can be compared to current investment costs), we suggest a more relaxed approach, where a rule-of-thumb may be:

Expansion part = (additional capacity / total capacity) x total investment cost

For instance, provided an overhead 220kV line is replaced by a new 380 kV line and the capacity approximately doubles, than half of total investment costs should be treated as network expansion and therefore applicable for an investment budget.

The approval should be granted for a certain time period by the national regulatory authority. Approvals are always granted on a project base. Alternative approaches that are practiced are

- Ex-ante approval of planned investment costs, and
- Ex-post approval of investment budget.

An ex ante approval of planned costs is given in advance of the construction and the TSO may increase tariffs accordingly. Ex-post, the actual project costs have to be compared to the approved costs. If these costs exceed the planned costs, The TSO has to apply for the cost difference in order to charge the additional spending in the network tariff. Vice versa, presuming that actual costs fall short of planned costs, the TSO is in charge to lower its network tariffs, accordingly.

An ex-ante cost approval involves the risk of high (ex post) monitoring costs. Besides, an ex-ante approval means that network tariffs have to be increased for the time of construction, in order to raise the revenue of the network operator.

We suggest benchmarking of the planned project costs first, before granting an ex-ante approval of an investment budget. The intention of the benchmark is to test cost efficiency, but not the usefulness of the investment. Usefulness may be tested in a separate welfare analysis. One feasible way is to assess the investment costs by standard values and compare the result to the project plan that has been worked out by the applicant. Typical investment costs for the construction of natural gas net-

works are represented in Table 7. The values have been collected from literature and from E-Bridge studies and refer to natural gas networks located in Central European countries.

Table 8 provides a comprehensive overview on investment costs of distinct asset classes of an electricity network (only primary equipment), which includes – among other

sources - results of former E-Bridge studies. Again, presented figures refer to investment projects in Central European countries. As a result of lower wages in South Eastern European countries, investment costs may be lower in these countries. Notably, standard values for secondary equipment can hardly be found in the literature. Thus, an assessment of investment costs for secondary equipment seems to be less straightforward.

Asset group	Type	additional type info	Unit	Source 1	Source 2
pipeline	PE, w/o digging	≤ 100mm	TEUR/km	30	-
	PE, w/o digging	≤ 400mm	TEUR/km	60	-
	Steel, w/o digging	≤ 100mm	TEUR/km	50	-
	Steel, w/o digging	≤ 400mm	TEUR/km	80	-
	Steel, w/o digging	≤ 800mm	TEUR/km	120	-
	Steel, total investment costs*	≤ 400mm	TEUR/km	-	750
	Steel, total investment costs*	≤ 800mm	TEUR/km	-	1.200
	Steel, total investment costs*	≤ 1200mm	TEUR/km	-	1.700
	Digging	unsealed and possible ploughing	TEUR/km	90	-
	Digging	unsealed and impossible ploughing	TEUR/km	150	-
stations	Digging	sealed and low traffic density	TEUR/km	200	-
	Digging	sealed and high traffic density	TEUR/km	450	-
	pressure regulating valve	400m ³ /h	TEUR/piece	12	-
	pressure regulating valve	3000m ³ /h	TEUR/piece	25	-
connections	compressor station	unspecified	TEUR/MW	-	1700 - 3000
	low pressure	≤ 1 bar	TEUR/piece	2.000	-
	medium pressure	≤ 4 bar	TEUR/piece	4.000	-

*average values; including secondary equipment and exit points

Table 7: Standard values of construction costs for typical asset groups (natural gas network)

Besides, it should be noted that the actual investment costs may vary heavily as a result, not only of economic influences (e. g. wages), but also as a result of solid and geographical conditions. High investment costs, that

exceed benchmark values, may still be efficient provided these conditions are unfavorable. Yet, the result of the benchmark test may be interpreted as a rough indicator for cost efficiency.

voltage level	Type	additional type Info	Unit	Source 1	Source 2	Source 3
LV	overland line	total investment cost w/o towers	TEUR/km	-	-	25
LV	masts	tower, type grey / poutrelle	TEUR/piece(s)	-	-	8
LV	underground cable + digging	unsealed and possible ploughing	TEUR/km	-	-	60
LV	Digging	sealing only	TEUR/km	-	-	100
MV	sealed underground cable	total investment costs	TEUR/km	-	-	184
MV	Digging	unsealed and possible ploughing	TEUR/km	40	-	-
MV	Digging	unsealed and impossible ploughing	TEUR/km	90	-	-
MV	Digging	sealed and low traffic density	TEUR/km	110	-	-
MV	Digging	sealed and high traffic density	TEUR/km	200	-	-
MV	Landline with leverage	3x50 AlD	TEUR/km	30	-	-
MV	Landline with leverage	3x95 AlD	TEUR/km	36	-	-
MV	Landline with leverage	3x120Al	TEUR/km	32	-	-
MV	Underground Cable	V PE Al 150	TEUR/km per circuit	18	-	-
MV	Underground Cable	V PE Al 185	TEUR/km per circuit	20	-	-
MV	Underground Cable	A PE Al 240	TEUR/km per circuit	22	-	-
MV	Transformer	110/220 or 110/10,20 MVA	TEUR/piece(s)	440	-	-
MV	Transformer	110/20 or 110/10,32 MVA	TEUR/piece(s)	500	-	-
MV	Transformer	110/20 or 110/10,40 MVA	TEUR/piece(s)	580	-	498
MV	Transformer	110/20 or 110/10,63 MVA	TEUR/piece(s)	790	-	-
MV	Switch Bay	20-kV, 25 kA, AIS	TEUR/piece(s)	25	-	-
MV	Switch Bay	20-kV, 25 kA, GIS	TEUR/piece(s)	41	-	-
HV	Leverage	single	TEUR/km	150	-	-
HV	Leverage	double	TEUR/km	180	-	-
HV	Digging	single and unsealed	TEUR/km	170	-	-
HV	Digging	double and unsealed	TEUR/km	200	-	-
HV	Digging	single and sealed	TEUR/km	220	-	-
HV	Digging	double and sealed	TEUR/km	250	-	-
HV	Overland Line	265/35	TEUR/km per circuit	30	-	-
HV	Overland Line	185/35	TEUR/km per circuit	20	-	-
HV	Underground Cable	V PE Cu240	TEUR/km	250	-	-
HV	Underground Cable	V PE Cu400	TEUR/km	300	-	-
HV	Underground Cable	V PE Cu630	TEUR/km	380	-	-
HV	Transformer	380/110, 100 MVA	TEUR/piece(s)	1.800	-	4.200
HV	Transformer	380/110, 200 MVA	TEUR/piece(s)	2.000	-	-
HV	Transformer	380/110, 300 MVA	TEUR/piece(s)	2.500	-	2.850
HV	Transformer	220/110, 100 MVA	TEUR/piece(s)	1.500	-	-
HV	Transformer	220/110, 200 MVA	TEUR/piece(s)	1.700	-	-
HV	Transformer	220/110, 300 MVA	TEUR/piece(s)	2.000	-	-
HV	Switch Bay	110-kV, 31,5 kA, AIS	TEUR/piece(s)	450	-	380
HV	Switch Bay	110-kV, 31,5 kA, GIS	TEUR/piece(s)	800	-	-
UHV	Leverage	220 kV, double	TEUR/km	280	-	580
UHV	Leverage	220 kV, quadruple	TEUR/km	360	-	-
UHV	Leverage	380 kV, double	TEUR/km	500	600	800 - 1200
UHV	Leverage	380 kV, quadruple	TEUR/km	730	-	-
UHV	Overland Line	265/35, two-part bundle	TEUR/km per circuit	80	-	92
UHV	Overland Line	265/35, quadri-part bundle	TEUR/km per circuit	150	-	-
UHV	tower	220kV	TEUR/piece(s)	-	-	102
UHV	Underground cable	220kV	TEUR/km	-	-	1.000
UHV	Switch Bay	220 kV, 40 kA, AIS	TEUR/piece(s)	1.200	-	-
UHV	Switch Bay	220 kV, 40 kA, GIS	TEUR/piece(s)	2.100	-	929 - 2200
UHV	Switch Bay	380 kV, 80 kA, AIS	TEUR/piece(s)	1.700	-	-
UHV	Switch Bay	380 kV, 80 kA, GIS	TEUR/piece(s)	3.300	-	-

Table 8: Standard values of construction costs for typical asset groups (electricity network)

Notably, the regulator may approve actual costs even during the construction phase and does not have to wait until finalization of the project. Still, there will be a time lag between the investment spending for the project (e. g. start of construction) and approved additional payoff by an increase of the revenue cap, which makes up usually 2 years. This time lag between investment costs and additional revenue stream will lead to additional capital needs and increase the capital costs of the TSO. The additional interest payments have to be considered for the cost approval. Besides, authorizing the investment budget ex post increases the regulatory risk for the applicant that costs will only be partly approved. High regulatory uncertainty may arise from that especially in unstable regulatory environments, and in countries with little approval practice.

In countries with insufficient access to the capital market and unstable regulatory environment and / or little regulatory experience, we suggest an ex ante approval. The pre-commitment of the regulator to pay an investment budget will reduce regulatory uncertainty. The approval may be combined with an ex ante benchmarking.

6.4.4 EX-POST MONITORING

The intention of an ex post benchmarking is not to test the “stand-alone” cost efficiency of an investment project, but to verify whether the new projects have been integrated in an efficient way into the existing network structure. Provided this is the case, the network efficiency in total shall not be decreased after the integration of the new assets into the regulated asset base.

In contrast to an ex ante benchmarking, an ex post benchmarking is not restricted to new established projects, but assesses the (cost) efficiency of the complete network. The tests are carried out periodically (for in-

stance before the start of a new regulation period). New assets, and corresponding output, will be included after the expiry of the investment budget and treated like any other existing assets.

We recommend carrying through a benchmark with a broad European data basis, as it has been developed, for instance, by Sumiscid. Their model E3 has been used in several European countries to compare the efficiency of electricity TSOs and uses three outputs:

- Normalized grid,
- Metric connection density and
- Capacity of connected power for renewable energy.

The Sumiscid approach is can be seen as a “lean” benchmark as it takes the network as given. Since the network is not compared to a green-field investment, the inefficiency results may be interpreted as conservative assessments of the actual inefficiency. Regarding electricity transmission networks, Sumiscid has collected wide European expertise.

Vice versa, we recommend an ex post approval for countries with longer lasting regulatory experience and a less restrictive access to the capital market, with the advantage of less bureaucracy and monitoring costs. A combination with an ex post benchmarking seems reasonable.

6.4.5 SUPPLEMENTARY ECONOMIC INCENTIVES

Some supplementary mechanism may increase cost efficiency and effectiveness of the investment budget and, as a consequence, strengthen the investment incentive, respectively.

In detail, we suggest to take into consideration

- the approval of higher capital costs (higher WACC) and
- the participation of network users in (deep) connection costs

as mechanisms to increase the effectiveness of investment incentives.

Note that establishing the supplementary mechanisms proposed in this section, may require some additional years of approval experience by the regulator.

Approval of higher costs of capital

For prioritized investment projects, the regulatory authorities may award rates of return above the normal estimate of the TSO WACC. Effective rate-of return adders lie between 1 and 4 percentage points, dependent on priority of the project and an assessment of regulatory risk. We suppose that, generally spoken, large-scaled gasification projects bear higher risks than expansions in electricity capacity, because of the high uncertainty on the future development of natural gas demand. Besides, investments in system reliability obviously bear a lower risk than network expansion projects.

A reasonable pattern for WACC increments could therefore be

- 4 percentage points for gasification projects (e. g. gas ring)
- 2 to 3 percentage points for projects to expand the capacity of the electricity transmission network
- 1 percentage point for restructuring of the electricity and / or natural gas network and for investments that increase network reliability

Of course, other values may be applied according to the specific economic situation of the country, specific

demands of the customers and the state of the networks.

Compensation of (deep) connection costs

The intention of construction subsidies is that newly connected customers should participate at the costs of necessary network expansions caused by the new connection. The level of these costs may be either ascertained by detailed project calculations, or the network operator may fix lump sum payments for stylized connection situations in advance.

Charged customers may be

- Large industrial customers, who apply for a direct connection to the transmission network
- Generators, in case that the planned feed-in capacity exceeds existing network capacity
- Distribution network operators who are connected to the transmission grid

The payment obligation will reduce the disincentive to apply for an over-dimensioned connection to the grid, which will only be incompletely used. Further, the network operator can use the subsidiary in order to finance the necessary investments. This is especially important provided the TSO has only limited access to capital markets.

We recommend introducing a construction subsidiary that should cover in average some 50% of investment costs caused by new connections. A higher charge may reduce the incentive for the TSO to plan its expansions cost effectively.

Further, it has to be taken into consideration that the payment of construction subsidiaries for connections to the natural gas grid may block a gasification strategy and

thus could be disadvantageous from an economic and political standpoint. Obligatory long-term booking of capacities could, instead, reduce the risk of over-

dimensioned connection capacities. However, the financing problem will remain unsolved.

RELEVANT LITERA- TURE

Australian Energy Market Commission, 2008, National Transmission Planning Arrangements, Final Report to MCE, 30 June 2008

Australian Energy Regulator (AER), 2007, "Regulatory Test version 3 & Application Guidelines", November 2007.

Brunekreeft, G., Neuhoff, K. and Newbery, D., 2004, Electricity Transmission: An Overview of the Current Debate, Cambridge Working Papers in Economics CWPE 0463

Brunekreeft, G., 2004, Regulatory Issues in Merchant Transmission Investment, Cambridge Working Papers in Economics CWPE 0422

Brunekreeft, G., Gabriel J. und Balmert, D., 2007, „Independent System Operators; ein Überblick“, Bericht Bremer Energie Institut, May 2007.

Brunekreeft, G., & De Nooij, M., 2009, "Value of Lost Load – zur Umsetzung der Q-Komponente in der Anreizregulierung", Energiewirtschaftliche Tagesfragen, Vol. 59, No. 6., pp. 34-38.

Bundesnetzagentur, Leitfaden zur Anpassung der Erlösobergrenze aufgrund eines Antrages zum Erweiterungsfaktor nach § 4 Abs. 4 Nr. 1 ARegV i.V.m. § 10 ARegV, 2009, Bonn

Bundesnetzagentur, Leitfaden zu Inhalt und Struktur von Anträgen auf Genehmigung von Investitionsbudgets nach § 23 Abs. 3 ARegV – im Bereich Elektrizität 2009, Bonn.

Bundesnetzagentur, Leitfaden zu Inhalt und Struktur von Anträgen auf Genehmigung von Investitionsbudgets nach § 23 Abs. 3 ARegV – im Bereich Gas, 2009, Bonn.

CAISO, 2004, "Transmission Economic Assessment Methodology (TEAM), California Independent System Operator, June 2004.

Commerce Commission, 2008, "Regulation of Electricity Lines Businesses; Targeted Control Regime - Threshold Reset 2009", Methodology Paper: Update, 25 June 2008, Wellington.

- CRE, 2008, Activity report, June 2008.
- De Nooij, M., 2007, Lessons for the appraisal of interconnection investments from the NorNed-case, OGEL, Vol. 5, No.1.
- Doucet, J. and Littlechild, S., 2006, Negotiated Settlements and the National Energy Board in Canada, Electricity Policy Research Group Working Paper, No.0629.
- DTe, 2004, Decision on the application by TenneT for permission to finance the NorNed cable in accordance with section 31 (6) of the Electricity Act of 1998. Dec 2004.
- ECRB, 2010, Cooperation of Regulators with Regard to Cross Border Investment Projects – Regulatory Instruments for Promoting New Investments — Assessment of Existing Mechanisms — Recommendations –
- ECRB, 2010, Regulatory Framework for the Development of the Energy Community Gas Ring, Discussion Paper on the Regulatory Instruments and Steps Necessary for the Development of the Natural Gas Market and Cross-Border Investments in the Energy Community
- Energieleitungsausbaugesetz - EnLAG (Kernstück des Gesetzes zur Beschleunigung des Ausbaus der Höchstspannungsnetze)
- Energienet.DK, GENERAL RULES FOR ENERGINET.DK GASTRANSMISSION'S OPEN SEASON PROCEDURE 2009
- ENERGY POLICY ACT OF 2005, PUBLIC LAW 109–58—AUG. 8, 2005
- ERGEG, 2007, Guidelines for Good Practice on Open Season Procedures (GGPOS).
- ERGEG, 2010, Final Advice on the Community-wide Ten-year Electricity Network Development Plan.
- ERGEG, 2010, 10-year network development plan for gas Final ERGEG Recommendations.
- EU, REGULATION (EC) No 715/2009 OF THE EUROPEAN PARLIAMENT AND OF THE COUNCIL, 2009.
- EU, REGULATION (EC) No 714/2009 OF THE EUROPEAN PARLIAMENT AND OF THE COUNCIL, 2009.
- FERC, 2006, Promoting Transmission Investment through Pricing Reform(Docket No. RM06 4-000; Order No. 679)

- Frontier Economics/Consentec, 2008, Improving incentives for investment in electricity transmission infrastructure, A REPORT PREPARED FOR THE EC November 2008
- Green, H., 2009, Commerce Amendment Act 2008: Impact on ELBs. NE-RA Economic Consultancy.
- Joskow P., Tirole,J. 2003, MERCHANT TRANSMISSION INVESTMENT, NBER, Working Paper 9534
- Hull, B. and Green, C., 2008, Offshore Electricity Transmission – Investor Presentation, 9th December 2008, Ofgem.
- Konsortium DEWI / E.ON Netz / EWI / RWE Transportnetz Strom / VE Transmission, Studie im Auftrag der Deutschen Energie-Agentur GmbH (Dena), Energiewirtschaftliche Planung für die Netzintegration von Windenergie in Deutschland an Land und Offshore bis zum Jahr 2020, Köln, 2005.
- Littlechild, S., 2004, Regulated and Merchant Interconnectors in Australia: SNI and Murraylink Revisited, Cambridge Working Papers in Economics CWPE 0410
- Littlechild, S., 2008, 'Some Applied Economics of Electricity Regulation: A Paper in Honour of David Newbery', The Energy Journal, Special Issue #2, pp.43-62.
- Littlechild, S., 2008, SOME ALTERNATIVE APPROACHES TO UTILITY REGULATION, Institute of Economic Affairs, pp. 32-37.
- Littlechild, S. and Ponzano, E., 2008, 'Transmission expansion in Argentina 5: The regional electricity forum of Buenos Aires province', Energy Economics, Volume 30, Issue 4, pp.1491-1526.
- Littlechild, S. and Skerk, C., 2008, 'Transmission expansion in Argentina 1: The origins of policy', Energy Economics, Volume 30, Issue 4, pp.1367-1384
- Littlechild, S. C., 2006, Stipulations, the consumer advocate and utility regulation in Florida, Electricity Policy Research Group Working Paper No. EPRG 06/15, 25 February 2006, Cambridge: University of Cambridge.
- Littlechild, S.C. and Cornwall, N., 2009, Potential scope for user participation in the GB energy regulatory framework, with particular reference to the next Transmission Price Control Review, Report for Ofgem. Available on Ofgem website.

Moberg, U., 2007, Future Nordic Grid Investments, presentation at ERGEG workshop, February 2007.

National Grid, 2009, Exit Reform Workshop, January 27th 2009,

NERA, 2006, Reform of NTS Gas Offtake Arrangements Report for the Gas Forum

Nordel, 2008, Nordic Grid Master Plan 2008

Ofgem, 2008, Electricity Distribution Price Control Review; Policy Paper, Ref.159/08, London: Ofgem.

Ofgem, 2009 Feb, Consultation ef: 14 /09 National Grid Electricity Transmission and National Grid Gas System Operator incentives from 1 April 2009, Ofgem, Feb 2009.

Ofgem, 2009 May, Electricity Distribution Price Control Review; Methodology and Initial Results Paper, Ofem, May 2009.

Ofgem, 2010, National Grid Electricity Transmission System Operator Incentives from 1 April 2010.

Ofgem, 2010, National Grid Gas System Operator Incentives from 1 April 2010.

PJM, 2010, Summary of PJM's Regional Transmission Expansion Plan (RTEP).

PJM, 2008, Manual 14B: PJM Region Transmission Planning Process.

PJM, 2010, OPERATING AGREEMENT OF PJM INTERCONNECTION, L.L.C.

Politt, M., 2007, Evaluating the evidence on electricity reform: Lessons for the South East Europe (SEE) market.

Pollitt, M., 2008a, 'The Future of Electricity (and Gas) Regulation in Low-carbon policy world', The Energy Journal, Special Issue in Honor of David Newbery, pp.63-94.

Pollitt, M., 2008b, 'Electricity reform in Argentina: Lessons for developing countries'

Energy Economics, Volume 30 (4), pp 1536-1567.

SUMICSID, 2009, International Benchmarking of Electricity Transmission System Operators e3 GRID PROJECT – FINAL REPORT.

Thomson, S. A., 2009, Terasen Gas – History of Negotiated Settlement Process in British Columbia, Canada, Presentation to SBGI Annual Conference, March.

LIST OF FIGURES AND TABLES

Figures:

Figure 1: : Work approach	5
Figure 2: Ratio Forecast outturn to allowance (Ofgem, Dec 2008, p. 72)..	35
Figure 3: Energy Community Gasring planned	58
Figure 4: Initial situation – electricity is used for heating.....	72
Figure 5: Electricity for heating has been substituted by natural gas consumption.....	72
Figure 6: Distribution of social benefits of gasification	73

Tables:

Table 1: NGET incentive mechanism (ofgem (2009) p. 12 (source: http://www.ofgem.gov.uk/Markets/WhlMkts/EffSystemOps/SystOpIncent/Documents1/Final%20proposals%20consultation%20document.pdf)	28
Table 2: Regulatory scheme for the electricity distribution networks in the UK (Ofgem, 2008; table 1, appendix 9, p. 110)	32
Table 3: High level overview of international practice of investment regulation.....	51
Table 4: Summary of the responses provided by the different NRAs in the 8 th region with respect to investment incentives in electricity.	56
Table 5: Summary of the responses provided by the different NRAs in the 8 th region with respect to investment incentives in gas	59
Table 6: Main areas for improvement of investment incentives in the electricity and gas industries in the 8 th region	64
Table 7: Standard values of construction costs for typical asset groups (natural gas network).....	80
Table 8: Standard values of construction costs for typical asset groups (electricitynetwork)	81

About E-Bridge Consulting

PROFILE

E-Bridge assists its clients in the implementation and realization of their corporate strategies. E-Bridge focuses on market structures and regulatory strategies, on the development and implementation of modern planning and operating processes and on the successful selection and implementation of the supporting IT-infrastructure. We provide international and practical expertise to solve the real issues and meet the challenges of our clients. As international exchange of knowledge is the core of its activities, E-Bridge and its consultants participate in several internationally respected industry-associations:

- Institute of Electrical and Electronics Engineers (IEEE)
- Conférence Internationale des Grandes Reseaux Étriques (CIGRE)
- Energietechnische Gesellschaft im VDE (ETG)
- Verband der Elektrotechnik, Elektronik und Informationstechnik (VDE)
- Österreichischer Verband für Elektrotechnik (OVE)
- Chemical Society
- World Energy Council
- Associated member of Eurelectric

E-BRIDGE'S STRENGTHS ARE ITS COMPETENCE, RELIABILITY AND INDEPENDENCE.

E-Bridge's superior advisory team combines engineering practice with economic and regulatory expertise. This forms the solid basis to become one of the leading consulting firms in the energy industry. The professional support of its clients is based on the international industry expertise and many years of consulting experience in the energy sector. E-Bridge has a strong team of committed consultants and it has also access to an international network of high-profile consultants. This is the guarantee for delivering added value to its clients and for shepherding projects through to successful completion. E-Bridge is independent of any market participant. This is demonstrated by its diverse client base, consisting of network operators as well as regulators, producers and traders. E-Bridge has no vested interest in any market participant or IT-vendor.

Project Authors



JENS BÜCHNER

E-Mail: jbuechner@e-bridge.com, Tel.: +49 (0) 228 90 90 65 0

Dr.-Ing. Jens Büchner, Managing Director of E-Bridge Consulting GmbH, has worked in the energy sector for more than 18 years. His extensive international experience, his solid grasp of technical and operational interrelationships and his understanding of complex economic and regulatory issues give him a broad foundation for consulting oriented to actual practice and implementation. He advises regulatory authorities and utilities in connection with complex, sensitive issues requiring both technical know-how and implementation-based experience.

Analytical expertise, along with many years of experience with virtually all of the international energy sector's key management issues, qualify Jens Büchner as a consultant for sensitive – and technically and economically challenging – tasks.

During his consulting career, he has played a key role in development of access regulations for electricity and gas markets, successfully supported major acquisition and merger projects in Europe and directed a range of management and cost-effectiveness studies. Jens Büchner holds a doctoral degree from RWTH Aachen University.



MARTIN BANDULET

E-Mail: mbandulet@e-bridge.com, Tel.: +49 (0) 228 90 90 65 0

His scope of work covers questions related to asset management and fixed-asset valuation of electricity and gas networks in context of regulation as well as topics related to grid access of natural gas. Prior to becoming a consultant, he worked for Thüga AG where he advised distribution network operators in questions of forthcoming regulation.



WOLFGANG ELSENBAST

E-Mail: welsenbast@e-bridge.com, Tel.: +49 (0) 228 90 90 65 0

Wolfgang Elsenbast has more than 13 years of experience in the field of regulatory policy. Prior to becoming a consultant at E-Bridge, he acted as consultant for the consultancy subsidiary of the "Institut der deutschen Wirtschaft" (IW) in Cologne. He extends E-Bridge's regulation and economic expertise by providing his substantial and practical experience in the field of regulatory and competition policy.



PHILIPP SCHMIDT

E-Mail: pschmidt@e-bridge.com, Tel.: +49 (0) 228 90 90 65 0

Mr. Philipp Schmidt has more than four years of experience inside the energy industry and worked for the management consultancies RWE Consulting and Perpetuo International Venture Management GmbH.

Mr. Schmidt was responsible for the evaluation, optimization and guidance of operative and strategic projects within the electricity and gas sector. His main focus of consulting is based on regulation management, gas transport, asset management and restructuring.

In his recent projects Mr. Schmidt was responsible for the planning and implementation of photovoltaic and wind projects in Central Eastern Europe.

Mr. Schmidt will support the team of E-Bridge with his experience in questions based on asset management and regulation management.

Contact

E-Bridge Consulting GmbH

Meckenheimer Allee 67

53115 Bonn

Germany

Phone: +49 (0) 228 90 90 65-0

Fax: +49 (0) 228 90 90 65-29

E-Mail: info@e-bridge.com

For further information on our projects, clients, and consulting partners, visit us at www.e-bridge.com.

Competence in Energy

