A zero-carbon European power system in 2050: proposals for a policy package

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ECN-E—10-041 April 2010

Acknowledgement
The authors are indebted to many colleagues who offered their advice, including Rebecca Collyer, Mike Hogan and Jaap Strengers (ECF), Julien Pestiaux, Matthias Gohl and Jurriaan Ruys (McKinsey), Simon Skillings (E3G), Felix Mathes (Oeko Institut), Nigel Jollands, Paolo Frankl, Tom Kerr and Peter Taylor (IEA), Jacques de Jong (CIEP), Remko Ybema, Jos Sijm, Martine Uyterlinde, Marc Londo, Bob van der Zwaan and Herman Snoep (ECN). This report is registered under ECN project number 5.0368.

Abstract
This ECN Working Document is part of the larger project *Roadmap 2050*, organised and financed by the European Climate Foundation. The project basically consists of three parts: analysis, policy advice, and outreach. This policy advice is based upon the findings of a fundamental scenario analysis by ECF on how a zero-carbon power system can be attained and which implications this has for the transmission grid, balancing and other aspects of security of supply (ECF Volume 1). The ECF analysis focused on the power sector. Two main items that should frame the agenda of the coming years have been identified, of which the second one can be broken down into five more specific items.

1. Drive faster investment in cost-effective measures to reach 20% end-use efficiency improvement by 2020; continue efficiency gains beyond 2020.
2. Start a transition towards a nearly full decarbonised power sector in the next five years, by:
    a. A timely retirement of existing high-carbon resources.
    b. Commercialization and deployment of critical low-carbon technologies.
    c. The creation of a durable business case for investment in low-carbon resources needed to meet demand growth and to replace planned retirements.
    d. A timely delivery of the required expansion in inter-regional power transfer capability.
    e. The creation of a business case for appropriate load management and smart grid investments.

For each policy issue a range of possible improvements to existing instruments have been suggested, or new approaches are suggested for consideration. Among those are:

- Improve existing policy to improve energy efficiency. To attain the 2050 target, annual efficiency improvement has to increase from 1 to 1.6% and the 2020 target has to be met.
- A further strengthening of the revised EU ETS Directive.
- Continue a strong effort to increase the share of renewable energy and substantially strengthen the introduction of CCS by policy packages.
- Connect the SET plan approach with deployment activities of member states.
- Draft national and subsequently regional roadmaps of the preferred zero carbon fuel mix.
- Make infrastructure a more ‘active’ part of the power sector and ask TSOs to draft long-term infrastructure plans to enable regional roadmaps.
- Consider how the current energy market design may be further improved (by strengthening the role of demand-side response and long-term contracts) or whether alternative designs (like capacity markets).
- Continue strengthening of emissions standards in transport and actively continue with demonstrations of clean technologies.
- Consider whether a Climate and Resource Directive to guide the development of greenhouse gas emissions in non-ETS sectors might be useful.

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Executive summary and main policy conclusions

S.1 The Challenge and what has to be done

This ECN Working Document is part of the larger project *Roadmap 2050*, organised and financed by the European Climate Foundation. The project basically consists of three parts: analysis, policy advice, and outreach. This policy advice has been linked to the findings of an energy scenario analysis carried out by ECF on how a zero-carbon power system could be attained and which implications this has for the transmission grid, balancing and other aspects of security of supply. The ECF analysis (Volume 1) focussed on the power sector. It included the need to replace fossil fuels in most or all buildings and much of the transport sector by nearly zero carbon electricity. It dealt with industry, heat or transport only in a more general way.

The technical analysis of *Roadmap 2050* by ECF(Volume 1) produced 9 main messages:
1. Much more aggressive exploitation of cost-effective efficiency measures is an essential component in all pathways studied.
2. To reach the 80-95% greenhouse gas emission reduction targets for 2050 a nearly fully decarbonised power sector is necessary; decarbonisation of key non-power sectors like passenger transport and heating depends strongly on zero-carbon power.
3. A reliable, affordable near zero-carbon power sector is feasible by 2050 with development of existing technology; technological breakthroughs may deliver it faster and cheaper.
4. This is achievable through a wide range of pathways; the study assessed three, ranging from 40% from renewable sources[1] and the balance from nuclear and CCS, to 80% from renewable sources[2], but every pathway faces significant (though somewhat different) challenges.
5. Baseload demand can be met reliably with a mix of dispatchable and intermittent sources, largely independent of the number of traditional ‘baseload’ plants in the supply portfolio.
6. A certain quantity of nuclear and CCS plants can operate normally alongside high levels of intermittent supply; this is not an impediment to attaining high shares of renewable energy.
7. All pathways foresee the emergence later this decade of rapidly expanding market demand for new, low-carbon generating capacity; this will not happen unless new high-carbon plants are effectively shut out of the market and existing high-carbon assets are retired on time.
8. A large amount of new trans-European transmission is required in all scenarios.
9. Driving investment in active load shaping capability is a key low-cost option for transmission optimization and system balancing.

This ECN Working Document describes how Europe could be able to implement effective policy instruments for reaching a nearly zero-carbon energy economy by 2050.

Attaining an energy system with zero greenhouse gas emission in Europe is not ‘more of the same’. While the actual 2020 target can be attained without fundamental changes, this is not the case with 100% CO_2 reduction in 2050. A clear sense of urgency is necessary that is conveyed and supported by European top leaders. A clear direction must be provided for the energy system and instruments to reach this aim. A set of policy instruments is needed that is consistent and tailor made to overcome all barriers. They have to provide clarity of the roles of governments, the private sector and other relevant parties. And finally, the approach needs to include

1 Current EU legislation effectively mandates approximately 36% of power from renewable sources by 2020.
2 The analysis addressed the feasibility of 100% from renewable sources by 2050; while it appears to be feasible to do so while maintaining acceptable levels of reliability and cost, it would most likely require the development of renewable resources in neighbouring regions for importation into Europe and/or technological breakthroughs, both of which are entirely possible, and both of which would produce a range of collateral benefits.

active and open communication to the public - voters and consumers - of the necessity of the road taken, its costs and benefits.

After having formulated the messages from the analysis and the main task ahead, a next step has been to determine the major challenges for policy emerging from this analysis. Two main items that should frame the agenda of the coming years have been identified, of which the second one can be broken down into five more specific aspects.

1. *Drive faster investment in cost-effective measures to reach 20% end-use efficiency improvement by 2020; continue efficiency gains beyond 2020.*
2. *Start a transition towards a nearly full decarbonised power sector in the next five years*, by:
   - Commercialize and deploy critical low-carbon technologies.
   - A timely retirement of existing high-carbon resources to create the required scale of market ‘pull’ for investment in new low-carbon resources.
   - The creation of a durable business case, through new wholesale market mechanisms, for investment in the capital-intensive, low marginal production costs low-carbon resources that will be needed to meet demand growth and to replace planned retirements.
   - Timely delivery of the required expansion in inter-regional power transfer capability.
   - Create a business case for appropriate demand-side management and smart grid investments.

In short, the task of the policy approach of this work document was to meet these challenges and search for options and approaches that address them in such a way that the ultimate aim in 2050 comes within reach but at the same time a feasible policy agenda for the next five years can be formulated. To reiterate: attaining a zero-carbon power supply is not ‘more of the same’. New policy instruments are urgently needed. All technologies are known, policy instruments have been investigated and most of them have been discussed or are being considered in several member states. It is also about risk management. When investments in generation, grids or energy efficiency are being considered, some options that are perceived as being too risky or complicated are not preferred, even when they would have made sense economically. Reduction of risks is therefore addressed in the policy package.

The subject of this working document is to investigate relevant policies while preserving or improving the effectiveness of the European internal energy market. It seems possible to attain a reliable and affordable zero-carbon power system. However, this requires considerable investments that are not foreseen yet, and both better implementation of existing policy instruments and adoption of new policy measures.

S.2 Benefits in all respects: energy efficiency

Many energy efficiency options exist that immediately earn money when implemented. This does not happen, however. Market and regulation failures prevent society to take cost-effective decisions. Practice and theoretical analyses have shown that integrated packages with an emphasis on regulation, in which it is tried to decrease transaction and information costs, are needed to formulate energy efficiency to the required level. At a certain level of ambition, high upfront investments become another barrier. Regulation and financial instruments are therefore to be combined.

Europe has a non-binding target for 2020: a 20% reduction in overall EU energy demand relative to a Business as Usual scenario. However, it is expected that end-use efficiency measures will deliver only 11% efficiency improvement by 2020. To attain 20% efficiency improvement by 2020 is crucial for reaching the *Roadmap 2050* ambition. Different countries show impressive approaches and new instruments are under consideration everywhere. But it takes too much time to learn from each other and to start implementation. In order to achieve the aim the annual energy efficiency improvement would have to increase from 1% in the past decades to 1.6%.

This would imply a two- to threefold larger policy effect. The policy questions are: how can we significantly accelerate investment in cost-effective efficiency measures? How can we ensure that these efficiency measures are sufficiently comprehensive and forward looking?

A policy package has been proposed in this document. The first two proposals do not contain fundamentally new ideas, but are about implementation and seriously making progress in making energy efficiency part of normal investment decisions.

1. Energy efficiency policy can only be successful by using integrated policy packages. A few elements of these packages could include:
   - An introduction of standards for new dwellings to ensure that at least half of the new buildings are passive houses by 2015 and 100% by 2020. A discussion is underway whether the EPBD should include a ‘near net zero energy’ ambition for new buildings by 2020. It is not fully clear what this would imply, nor what the additional costs would be in different countries. The closer the actual target could be to this ambition, the better it would be as long as additional costs could be paid back in a period comparable with the lifetime of an average period of amortisation, say 30 years.
   - An extension of the EPBD to all existing buildings to ensure that annually 2 - 3% of the building stock will be refurbished in all member states, to take place with removal or general renovation, in which owners and tenants are obliged to improve the efficiency of their homes; to ensure that social housing organizations take the lead in this approach and innovate, teaching the construction sector that efficiency improvements are possible and training workers. This will need effective delivery mechanisms such as establishing quality controls for the information and retrofit installations provided to households.
   - Different ways of dedicated, consistent public funding would be needed to leverage private investment, such as upfront financing by means of low interest loans or tax reductions. Additionally, Member States would have to organise sufficient enforcement and verification of these regulations.
   - An automatic adjustment of Ecodesign standards and labels to technological improvements.
   - Introduction of energy efficiency obligations for utilities (white certificates) and other ways to create new business opportunities along the energy efficiency chain to spur innovation and productivity improvements. To be effective, energy efficiency obligations must have sufficient ambition.

2. The toolbox of policies is well-known. It needs high-level, long-term political commitment to attain it. This is the reason why ECN’s advice is to evaluate within the term of this Parliament whether the current non-binding targets are on track and to reconsider this policy, including the option of a legally binding target if this is not the case.

The fourth instrument is a new one.

3. An additional instrument could be the introduction of a Climate and Resources Directive. We suggest the Commission to consider drafting a Directive that would bind the member states to propose a Climate Law, of which some elements are:
   - An independent mechanism that checks progress and makes proposals on next steps and instruments.
   - Intermediate targets. We suggest a linear path of CO_2 reduction compared with 1990: -30% in 2020, -45% in 2030, -65/70% in 2040.
   - Giving attention to aspects of justice and the position of low income groups.
   - Guidance on appropriate measures within a 2050 ‘resource envelope’ to avoid taking attractive short-term measures that work against attainment of longer term goals.

All other elements could be completed by the member states according to their different preferences and situations. This new instrument would offer a framework in which a long-term approach is guaranteed.

A sustainable energy future includes a new way of transportation. The internal combustion engine certainly will further improve, but will have been replaced to a great extent in 2050. It is not known yet which successor has the best cards, but the chances for the electric vehicle are good. The ECF study did assume that electrification will be the choice for light- and medium-duty vehicles (hydrogen and other options have not been ruled out, and they would only reduce the size of the challenge in decarbonising the power supply). The larger part of the road transport sector (excluding long-haul trucking) is expected to use electricity from batteries or hydrogen as an alternative. For these two technologies, technology-specific support is recommended. The timing of these policies depends on technological progress and consumer acceptance. Industry and public actors are investing hugely in this option and therefore it has to be included in our considerations about a new power system. Electric vehicles contribute only significantly to greenhouse gas reduction if the electricity generation is zero-carbon, which is the case in the ECF pathways. Transport is on the eve of a revolutionary change, but how and when is still uncertain. ECN suggests to consider:
- Increasingly tough standards for passenger cars (2020 still possible with internal combustion engine, next one not).
- Short-term investments in investing in demonstration and learning of electric vehicles (EV) and EV concepts; also development of hydrogen technologies and infrastructure.
- A massive introduction of new technology after 2020. The standards will incentivise this.
- Trucks, ships and planes probably to be fuelled mainly by biofuels.

S.3 Drive commercialisation and deployment of critical low-carbon technologies: Huge improvements of technology needed

Recently the Strategic Energy Technology (SET) plan has been adopted, which is an important start of a joint European approach towards clean energy technologies. However, the approach is unrelated to deployment and funding has not been fully organised. Significant scope exists for improvement in cost and performance of low-carbon technologies. Many member states have created support mechanisms for a range of renewable energy technologies but performance varies widely. CCS is a crucial technology[3] but is lagging due to high costs, uncertainty about future prospects and in general a failure of EU member states to enact necessary legal frameworks. The main issues to be solved are:
- How to support commercial deployment of a sufficiently broad range of promising emergent low-carbon technologies?
- How to plan for phase-out of support mechanisms as technologies mature?
- Nuclear is a mature technology, but how can support become appropriate in regulatory standardisation and action on high-level waste storage?

The way forward could be as follows:
1. Adopt an explicit combination of the greenhouse gas reduction target and the deployment and RD&D for specific technologies. Partly this could be done at the EU level by a implementation of the SET plan. This could involve the formulation of roadmaps for relevant renewable energy technologies, emerging transmission and ‘smart grid’ technologies, CCS and nuclear, as has been started in the SET process. It also could include a deployment focus and all relevant policy instruments. In an interactive process this could result in a forward looking 2050 fuel mix and technology vision for the power sector that combines the different roadmaps and could be linked with the regional long-term roadmaps on the fuel mix and long-term regional infrastructure plans as will be proposed in the next pages.

[3] Particularly in certain non-power industry sectors, not analysed in this report.

Technology policy is specific. It makes choices about which technologies are to be developed more than others, it makes priorities and posteriorities. The potential learning rates and industrial opportunities for member states are important considerations to take into account. With regard to technology the next steps are suggested.

2. For renewable energy:
   - A preparation for a post-2020 situation in which the share of renewable energy has been further increased. Smart grids, preparation of how to deal with intermittency issues are needed. Grids could become the enabler of specific regional (neighbouring countries) approaches. Visions on the long-term fuel mix, including a timely consideration on how to continue the incentive system, and frameworks of infrastructure development will enable governments to develop a post-2020 view on renewable energy.
   - No common European incentive system is needed by now as the start of a formal discussion on this topic would disrupt existing investment plans and create uncertainty in the market.
   - Before 2015 the development of costs, recent experiences in incentive systems and their possible convergence may be assessed in order to investigate whether time is ripe to make a step forward towards a more common approach.
   - As a result of a strong global effort of investment in renewable energy, the implication of the ECF analysis (Volume 1) is to expect that by 2030 almost no subsidies or green certificate stimuli for new investments would be necessary due to the decreased costs of most renewable energy technologies, a higher carbon price caused by a more stringent ETS cap and combinations of market and regulatory mechanisms that at a certain moment would effectively discourage construction of new high-carbon plants.
3. Next to EU ETS, additional temporary incentives could be considered for deployment of CCS as they are with emergent renewable energy technologies. All new coal-fired plants built from today and eventually also larger gas-fired plants need to be capture-ready to prevent lock-ins. Small-scale CCS demonstration plants are operating or being built now and large-scale demo investments are foreseen in 2014-16. Initial cost differences between capture, small volumes of transport and storage, and the emission price are expected to remain to be too high for autonomous deployment of CCS. Therefore additional demonstrations are needed and it is suggested to invest in financial facilities, probably as a part of a broader policy package (cf. S5) The difference between costs of CCS and unabated fossil fuel plants will differ from place to place and country to country and the CO_2 transport and storage infrastructure still needs to be developed. Temporary financial instruments could include the first stages of deployment of CCS as a follow up of the current demonstration activities. An ECN study has indicated that the costs of this type of financial support could be relatively small (Groenenberg et al, 2010). The SET plan roadmap could overview this process to enable joint European learning. It is advised to consider by 2015 what has been learned and what is the best way forward.
4. Nuclear power is a mature technology and no specific subsidies are appropriate on commercialisation grounds. Some have argued for support based on other grounds. However, the ECF analysis of the energy security and system reliability impacts of power sector decarbonisation confirms that nuclear power is not more or less than one of a number of low-carbon supply options, with its own advantages and disadvantages. To stimulate a cost-effective European approach, those countries that have chosen in favour of nuclear energy could consider seeking solutions for final end-storage of high-level waste, if possible in the context of a regional market. Streamlining of regulatory processes will enable all of them to benefit from standardisations.

New technology aspects of infrastructure (smart grids) will be mentioned in the next section. Non-ETS sectors have been mentioned already: standards for new and existing buildings, demonstration activities and other aspects of the proposed packages including the suggested new instrument of a Resource or Climate Directive will all drive innovation and clean technologies. A technology-specific approach also deals with what should be ended. If a fully decarbonised power system is the aim, national subsidies to produce coal are an anomaly.

S.4 Create a market 'pull' for investment in low-carbon

The European emissions trading system (ETS) is a key instrument for greenhouse gas emission reduction. However, at this moment the ETS target does not lead to the energy technology investment decisions that are needed on the road to carbon free electricity generation in 2050. It is uncertain if the ETS will provide a requisite long-term investment case.

The EU ETS Directive has specified the annual caps of EU emission allowances for the third trading period (2013-2020) and beyond, i.e., the linear factor by which the annual amount of EU allowances (EUAs) shall decrease is 1.74% in relation to the average cap for the second phase. This linear reduction factor may be revised by 2025 at the latest.

There are reasons for seeking more clarity about the emissions cap and to consider additional policy instruments. In order to achieve the overall *Roadmap 2050* target in general and 2050 mitigation target for the power/other ETS sectors in particular, the mitigation factor has to be intensified. To succeed in defining an effective long-term pathway, the EU is recommended to agree with an overall greenhouse gas emission reduction target of 30% in 2020 compared to 1990, implying an annual reduction of ETS emissions by 2.75% over the period 2013-2020. The extent to which CDM is allowed for meeting this reduction rate has to be diminished. Next, to reduce uncertainty, the trajectory of emissions reduction can be made much clearer. Transparency in annual absolute amounts of emissions in the periods that are relevant for current investment decisions - not only 2020, but also 2030, 2040 and 2050 - have to be provided. Linking of the EU ETS to the CDM or other crediting systems is proposed to be reduced to a relatively low percentage, e.g., 5-10%, of total required emissions reductions beyond 2020.

There are sound arguments for introducing a EUA price floor/ceiling in the EU ETS but it also raises a variety of risks, challenges and other problems. Therefore, we recommend to (i) conduct a serious, independent study on the extent to which EUA price instability/uncertainty is a problem for the long-term environmental and cost effectiveness of the scheme and, if yes, whether and how this issue could be addressed by a system of price floors/ceilings, (ii) consult a variety of stakeholders and experts on the issue of EUA price stabilisation, and (iii) based on (i) and (ii), decide and propose whether and how a EUA price floor/ceiling could be introduced as part of the EU ETS.

It is uncertain to which extent a strengthened EU ETS is able to provide the overall framework for the large investments that have to be made. Other instruments can help to overcome market failures that e.g. inhibit the adoption of energy efficiency and carbon saving technologies and technology innovation and diffusion. Other instrument can also help to reduce uncertainty. Therefore, complementary measures need to be considered. They could be of regulatory or financial nature, and a combination is also possible. They all have advantages and disadvantages. The design of an optimal policy mix is a matter of careful fine-tuning of mutually consistent instruments, which each instrument addressing a specific objective or market failure.

A policy package of financial incentives and regulation is expected to improve the investment climate for clean technologies by reducing uncertainty. It probably could diminish 'wait and see' behaviour of investors and contribute to a virtuous circle. It could show that the pathways of *Roadmap 2050* are indeed feasible. It could deliver empirical arguments that further reductions of the emissions cap after the one suggested in this report could be considered.

To conclude, in order to reduce uncertainty and further contribute to the internal market and European security of supply, additional policy measures next to strengthening of ETS need to be considered and must be designed with great care.

S.5 Create a durable business case for investments in long-lived, low-carbon, capital-intensive resources

ETS as it is now does not drive long-term investment in low-carbon resources. The liberalised wholesale power market currently is too short-term and too one-dimensional: sustainability and possibly security of supply are taken into account in portfolios of investors, but these are dominated by investments that are easy to build (gas-fired plants) or driven by subsidies. A nearly zero carbon power system will be completely different from the current one. It will be dominated by capital-intensive sources with low marginal cost. As the price of electricity in a sufficiently competitive market equals marginal costs (of the marginal supplier in any given pricing period), this power system is expected to show very volatile prices that will sometimes be zero or negative and sometimes be very high. The adequate regulation of such a market raises new questions. Concerns may be voiced about the ability of current energy-only wholesale markets to drive timely investment in capital-intensive assets. Issues to be solved are: how can the liberalised market become better at valuing the need for new long-lived system resources in a timely fashion? What policy interventions are appropriate and how should they be implemented? How to ensure that efficiency and demand response measures are evaluated as alternatives to investment in new supply? How to ensure that they are able to deliver?

Three proposals are made.

1. Governments are advised to draft 'regional roadmaps' of the preferred power mix aiming at concrete proposals on how to actually attain a zero-carbon power system. These roadmaps could be formulated in close cooperation with relevant stakeholders, as these are the ones who will invest (power generation companies), have to pay (consumers), enable (grid companies, local governments) or are otherwise relevant stakeholders (NGOs). They gradually could become regional, as regional markets will unite gradually. This will be a step by step process, from purely national to more regional approaches. The EU has a role to play in encouraging these national and regional processes, directly by supporting them with e.g. funding for the required resources, or even requiring that they be carried out, with the discretion left to Member States on the specific format and venue. The roadmaps could be the basis for infrastructure policy as will be sketched in the next section. These roadmaps are no 'plans', but may increase transparency in licensing and stability in the degree of government support to zero-carbon generation investments. This will diminish regulatory risks, which are larger in a more capital intensive system.
2. Demand-side response (load shaping, next to energy efficiency measures) has to get considerable more policy attention, as it improves the reliability of the power system and diminishes the need for additional investments.
3. It might be expected the current 'energy only' market (in which capacity is not rewarded separately) will not be able to deliver the investments in the power system that are needed and significant improvement have to be considered. It is important that flexible and uncapped prices are allowed and long-term contracts can be used to facilitate financing structures in capital intensive generation; the long-term contracts have to be able finance e.g. the amortization period of the debt required to build the power plant. Reduction of regulatory risks leads to a cost decrease in all cases. At some moment additional capacity mechanisms might become necessary. To be prepared for a lack of investment a serious study of pros and cons of capacity mechanisms could be organised by the European Commission that could suggest conclusions before 2014.

As the transition towards a nearly fully decarbonised power system is without precedent, it is a process in which joint learning is crucial. It is suggested that both the progress of the policy packages and of the different approaches in member states to attain the ambitious aim are evaluated before 2015 to judge whether sufficient progress has been made. Anticipated evaluations, like the one with regard to national renewable energy policies or CCS, could be dovetailed with such a broader progress report.

S.6 Assure timely delivery of the required grid expansion and achieve smart grid investments

The main part of the existing European power grid has limited inter-regional transfer capability. Indigenous low-carbon resources are plentiful but unevenly distributed across the EU. Aggregate on- and off-peak spread across the EU is much lower than localised spreads, but the effect emerges over a wide geographic area. To a large extent solar PV and wind power are inversely correlated in Europe. The current structure of the single market, with no locational pricing, no regional infrastructure planning is not designed to deliver the transmission or distribution infrastructure for a zero-carbon power system. The issues to be solved are: who will be responsible to create the plan for grid expansion, based on what objectives, with what transparency and with what competencies to act? Will the process maximise the chances for broad public acceptance? How will the inter-regional infrastructure be financed and who will own it? Who will operate it to ensure reliability, including optimal deployment across regions of reliability-related services such as spinning reserve? And who will regulate inter-regional infrastructure?

However, intra-regional transmission is only one side of the infrastructure coin. If the power system would achieve a 20% reduction of peak demand due to demand-side response by 2050, 15 to 25% less grid capacity would be needed for all pathways[4]. This is only possible if hard and soft infrastructure for 'smart' load management is implemented by the mid-2020s to support the 2050 ambition. New technologies and new operational practices will require considerable amounts of testing; only multiple pilot models will deliver the necessary diversity. The current regulatory framework is poorly adapted to driving investment, however. The issues to be solved to attain smart grids on time are: how to drive the needed investments through regulatory frameworks? What is the right balance between top-down (European approaches, standards to ensure compatibility) and bottom-up (local initiatives)? What are the strategic priorities? How to support a sufficiently wide range of pilot projects?

Possible solutions for these issues are as follows.

1. As infrastructure is becoming more important, the situation in which it is only allowed to be a 'passive' partner in the power system has to finish. Infrastructure will get a more active and leading role. Locational pricing in both transmission and distribution grids stimulate cost effective siting of generation and could be promoted (even when it would mean that temporary subsidies for the average renewable energy plant have to increase). The European Commission could propose ENTSO-E to draft an European Infrastructure Plan that corresponds with the roadmaps on the energy system that has been proposed in the preceding sections, to be drafted by governments at the level of the Regional Markets in close co-operation with relevant stakeholders and to be based on one or several zero-carbon scenarios such as those of ECF. This back-casting approach can build upon the approach that has been included in the 2009 Third Energy Package in which regional TSOs have to draft regional grid plans every two years, which are combined by ENTSO-E into a two-yearly European Infrastructure Plan. The suggestion ECN makes is to use this approach, but look further ahead and combine it with back-casting scenarios.
2. Grids could explicitly get the task to facilitate a reliable zero carbon energy system by 2050 with equal priority to cost effectiveness and supply security. The principal task of ACER (the Agency for the Cooperation of Energy Regulators) could become to "promote the development of a fully reliable, fully decarbonised, energy infrastructure" in Europe. It could have a role in convincing national regulatory authorities to allow necessary investments

[4] Depending on the pathway, the need for additional back-up generation would decrease from 14-15% of installed generation without demand-side response to 9-10% with 20 per cent demand-side management.

and, more generally, could play an active role in enabling a European sustainable transmission grid. Its planning mandate could expand beyond the existing one to make a long-term approach feasible. ACER could support a transparent process by the regional TSOs in which they demonstrate how customers and producers are committed to use new grids for a longer period.

3. In this way more funding becomes available. Further additional funds could be searched for, such as the Structural and Cohesion Fund and additional funding of the SET Plan for smart grids. As part of the overall review of the EU budget allocation of funds to energy infrastructure could be considered. Communication with all stakeholders should search for local benefits as in the end local stakeholders will only accept new investments if they also perceive a benefit.
4. Balancing becomes more important and will remain a responsibility of regulated grid operators. However, grid operators must become more regional in scope and authority, since it will be impossible to deliver reliable operation in any of the decarbonised pathways based on the currently envisioned population of autonomous grid operators. Storage may use price differentials, and investment in storage has market opportunities.
5. Regulation of distribution networks must facilitate three crucial aspects of a zero-carbon network: the rollout of smart meters, the development of distributed generation, and smart grids, probably even by some kind of overcompensation and incentives for innovation. Several approaches are feasible to encourage these three features in an economic efficient way. As national regulatory frameworks differ, no 'one size fits all' approach is feasible: Pilots and joint learning are the way forward. Funding and guidance for a coordinated programme of pilot projects to demonstrate technologies and operative practices in both member states and at the EU level are crucial.
6. More generally, a combination of 'top-down' (from Europe to the regions and nations) and 'bottom-up' (from the nations and regions to Europe) approaches is needed. Some top-down guidance remains necessary as the ultimate aim is one European infrastructure. But, as the experience with regional markets has shown, most progress will be made by experiments. The North Sea could be an interesting example of establishing a Regional Transmission Operator.

S.7 Europe and its member states

The Lisbon treaty has recently taken effect. Energy will become a relevant topic of its own in European legislation. But still the question whether specific decisions and regulation are most effective at the European or at the national level remains highly relevant. In this report it will be argued that a European system of greenhouse gas emissions trading has to be further improved by decisions to be taken in the next years. But to stimulate renewable energy, different national systems may remain for some time and there is ample time to learn from each other; a decision whether one European system is needed doesn't have to be taken yet. Cooperation between countries at a regional level could be a stepping stone towards more common approaches. Energy efficiency policies will mainly remain national. This is also the topic in which European cities are playing an increasingly important role. Finally, a case for national CO_2 taxes in non-ETS sectors exists. Several European countries have taken the lead by increasing an energy or CO_2 tax, decreasing taxes on labour. These taxes only slowly become really effective as they tend to start low but increase gradually. Although politically difficult, such an approach has shown to be an effective policy tool.

To summarise, it is suggested to consider the next five years:

Considerations at the EU level

- Promote joint learning in policies in all respects and don't be afraid for experiments (e.g. Regional Markets).
- Strengthen standards (Ecodesign, cars) and extend regulation (EPBD) to all buildings.

- Introduce a mandatory efficiency target if necessary.
- Introduce a Climate and Resource Directive.
- Strengthen the 2020 EU ETS cap, including reduction of the clean development mechanism (CDM) to a low percentage.
- Conduct an independent study on the extent to which EUA price instability/uncertainty is a problem for the long-term environmental and cost effectiveness of the scheme and, if yes, whether and how this issue could be addressed by a system of price floors/ceilings.
- Provide transparency in annual absolute amounts of emissions in the periods that are relevant for current investment decisions - not only 2020, but also 2030, 2040 and 2050.
- Consider additional policy measures, both financial and regulatory, to stimulate carbon capture and storage (CCS) and discourage high-carbon assets.
- Ensure that additional funding for SET is available. Include deployment policies in SET Roadmaps; make Roadmaps ‘living documents’ in cooperation with the IEA.
- Evaluate by 2015 how renewable energy (RE) policy instruments can be improved.
- Collect information on level of subsidies/encouragements with respect to RE for the next 10 years and formulate policy/advice which combination of RD&D and deployment might be most effective.
- Commission a study of whether the current power market design is capable to drive forward investment in low carbon generation and when changes are needed, in order to decide on eventual alternatives before 2015.
- Ensure funding of infrastructure enlargement and modernization (strategic transmission, smart grids).
- Give transmission operators (ENTSO-E) and regulators (ACER) additional mandates, including the task of aiming at zero carbon power system.
- Give ACER task to promote European infrastructure and of overseeing process of interconnection development.
- Establish common framework for regulating networks to deliver smart grids.

Considerations at the level of the member states
- Implement deployment strategies for energy efficiency by policy packages in order to significantly increase the policy effect.
- Consider ‘greening’ of the tax system.
- Focus RD&D on technologies with high return (learning curve, industrial opportunities).
- Organise large scale demonstrations for new transport technologies.
- Attain the 20% renewable energy target in 2020 and prepare further deployment.
- Organise large CCS demonstration activities and regulate transport and storage step by step.
- Consider introducing a CCS policy package for the next stage (after 2020).
- Decrease regulatory uncertainty and consider standardization of planning permission process for nuclear energy.
- Consider a regional approach for storage of high radioactive nuclear waste.
- Develop policies to increase demand-response.
- Further develop regional markets as zones of experiment; consider a regional transmission operator in North Sea.
- Draft national and gradually regional roadmaps of preferred 2050 zero carbon fuel mix.
- Suggest national and gradually regional transmission operators (TSOs) to develop infrastructure plans enabling these roadmaps (incl. sharing of back-up capacity).
- Reform the regulatory framework to deliver smart grids and invest in demonstrations.

Box S.1 *Europe is not alone…*

Some features of the 2050 power system compared with a global outlook

In its recent World Energy Outlook (2009g) the IEA describes a 450 ppm scenario, that is in line with the 2050 BLUE scenario (IEA 2008) in which a 50% GHG emission reduction is attained worldwide in 2050 compared to 1990. This global ambition is comparable with the *Roadmap 2050* scenario and some crucial assumptions (e.g. energy prices, GDP growth) of the ECF pathways are based on this IEA scenario. The 450 ppm scenario policies are attained by a combination of emissions trading, sectoral agreements and additional policies, backed by an intensification of technology policy. Emissions trading will start by now in the OECD region (including all EU members) and extend to countries like China by 2020. A credible ETS reduction target results in 2030 CO_2 emission prices in OECD countries (including all EU members) of 110$ (75 EUR) per tonne CO2 and in other Major Economies taking part in the system of 65$ (45 EUR). This policy scenario leads to fundamental changes in the global power system after 2020: even including electric transport, the power sector is responsible for two thirds of the emission reduction compared with a Reference scenario, and 40% of the difference is due to demand reduction; up to 75% of new capacity in OECD countries are in renewable energy or nuclear, and all new coal-fired capacity after 2020 will be equipped with CCS (these global capacity increases are important for the attainment of the European zero-carbon scenario, because cost reduction is driven by learning curves and global capacity increase). The European power system in 2030 in this scenario is clearly upon its way towards carbon neutrality, which is fully in line with the ECF Volume 1 analysis that carbon emissions in the power sector in 2030 could reduce by 70% related to 1990. Overall European energy CO_2 emission would have been reduced from 4000 Mton in 1990 to 2270 in 2030 and are decreasing rapidly. Coal-fired power plants are gradually mothballed or disconnected from the grid. The first CCGT plants with CCS are appearing.

EU Fuel mix of power generation, IEA 450 ppm scenario

[%]	2010	2020	2030
Coal	30	18	8
(of which CCS)			3
Gas	20	23	18
(of which CCS)			2
Nuclear	30	28	29
Renewables	20	31	45

If the market would be convinced of the irreversibility of the policy approach, the IEA indicates that a high CO_2 price will lead to a strong reduction of the share of coal. European power generation is already for 80% carbon free by 2030. Parallel with CO_2 reduction in the power sector, due to strong policies the transport sector is being decarbonised. CO_2 intensity of new cars decreases due to credible standards from 170 g CO_2/km in 2007 to 110 g in 2020 and 80 g in 2030. In this way only 40% of new passenger cars in 2030 are driven by internal combustion engines, hybrids take up 30% and the remaining part is plug-in hybrid and electric.

Huge investments are needed for this policy scenario, most of which (45%) in the transport sector due to more expensive cars; 25% of additional investments are in low carbon buildings and appliances, 20% in a more capital-intensive power sector. Renewable energy is moving fast but CCS is still in its pre-commercialization stage. Investments in renewable energy, CCS and nuclear are 88 resp. 94% of overall investments in generation in the European power sector - with effective policies carbon neutrality is approaching rapidly.

Next to lower carbon emissions, other rewards would be impressive. Due to a lower demand and lower fossil energy prices, the EU energy import bill in 2030 would have decreased with one third compared to the Reference scenario. Without additional policies the EU oil and gas import bill would increase with 45% in 2007-30. The EU will remain the largest importer of oil and gas in the world (before the US and China). This reduction is in line with the outcome of the ECF Volume 1 analysis, which shows how the volume of gas and coal imports will have been reduced by 80% in a pathway leading to 80% renewable energy in 2050. Besides, a large part of new clean technology will originate from OECD countries. ECF analysis indicates how this could lead to a further increase of European jobs in 2030-50. In absolute figures business services and construction benefit most from the clean pathways; related to the baseline, employment in mechanical and electrical engineering would benefit most.

1. Introduction

This ECN Working Document is part of the larger project *Roadmap 2050*, organised and financed by the European Climate Foundation. The project basically consists of three parts: analysis, policy advice, and outreach. This policy advice is based upon the findings of a fundamental scenario analysis by ECF on how a zero-carbon power system can be attained and which implications this has for the transmission grid, balancing and other aspects of security of supply. The ECF analysis focussed on the power sector. It included the need to replace fossil fuels in the buildings and part of the transport sector by nearly full decarbonised electricity. It did not deal with industry, heat or transport in a more general way.

The technical analysis of *Roadmap 2050* by ECF produced 9 main messages:

1. Much more aggressive exploitation of cost-effective efficiency measures is an essential component in all pathways studied.
2. To reach the 80-95% greenhouse gas emission reduction targets for 2050 a nearly fully decarbonised power sector is necessary; decarbonisation of key non-power sectors like passenger transport and heating depends strongly on zero-carbon power.
3. A reliable, affordable near zero-carbon power sector is feasible by 2050 with development of existing technology; technological breakthroughs may deliver it faster and cheaper.
4. This is achievable through a wide range of pathways, from a minimum of 40% from renewable sources[5] and the balance from nuclear and CCS, to 80% from renewable sources[6], but every pathway faces significant (though somewhat different) challenges.
5. Baseload demand can be met reliably with a mix of dispatchable and intermittent sources, largely independent of the number of traditional ‘baseload’ plants in the supply portfolio.
6. A certain quantity of nuclear and CCS plants can operate normally alongside high levels of intermittent supply; this is not an impediment to attaining high shares of renewable energy.
7. All pathways foresee the emergence later this decade of rapidly expanding market demand for new, low-carbon generating capacity; this will not happen unless new high-carbon plants are effectively discouraged out of the market and existing high-carbon assets are retired on time.
8. A large amount of new trans-European transmission is required in all scenarios.
9. Driving investment in active load shaping capability is a key low-cost option for transmission optimization and system balancing.

After having formulated the messages from the analysis and the main task ahead, a next step has been to determine the major challenges for policy emerging from this analysis. Two main items that should frame the agenda of the coming years have been identified, of which the second one can be broken down into five more specific aspects.

1. *Drive faster investment in cost-effective measures to reach 20% end-use efficiency improvement by 2020; continue efficiency gains beyond 2020.*
2. *Start a transition towards a nearly full decarbonised power sector in the next five years*, by:
   - Commercialization and deployment of critical low-carbon technologies.
   - A timely retirement of existing high-carbon resources to create the required scale of market ‘pull’ for investment in new low-carbon resources.
   - The creation of a durable business case, through new wholesale market mechanisms, for investment in the capital-intensive, low marginal production costs low-carbon resources that will be needed to meet demand growth and to replace planned retirements.

[5] Current EU legislation effectively mandates approximately 36% of power from renewable sources by 2020.

[6] The analysis addressed the feasibility of 100% from renewable sources by 2050; while it appears to be feasible to do so while maintaining acceptable levels of reliability and cost, it would most likely require the development of renewable resources in neighbouring regions for importation into Europe and/or technological breakthroughs, both of which are entirely possible, and both of which would produce a range of collateral benefits.

- A timely delivery of the required expansion in inter-regional power transfer capability.
- The creation of a business case for appropriate demand-side management and smart grid investments.

In short, the task of the policy approach of this work document is to meet these challenges and search for options and approaches that address them in such a way that the ultimate aim in 2050 comes within reach, but at the same time a feasible policy agenda for the next five years can be formulated. Actual policies do not deliver sufficiently. More is needed. To formulate such an agenda, the 'leading principles' of the necessary policy instruments[7] must first be examined.

Both McKinsey (Global Greenhouse Gas Abatement Cost Curve) and the IEA (2008) have developed cost curves of abatement options. These cost curves consist of three parts:

- End-use energy efficiency options are very cost-effective. In the cost curves their marginal costs are negative. Typical examples are insulation of existing buildings and other energy efficiency measures with a short pay-back time. Due to all kinds of barriers, such as transaction costs and other impediments, these measures are not implemented, although they would benefit individuals and society immediately. Only packages of policy approaches will tackle these 'transaction costs', but *regulation* is assumed to play an important role in the package.
- In the middle part of the cost curve, which is relatively flat, investments may be found that could be done with relatively low costs. However, without some kind of financial incentive, this will lead to a negative result for the investor. He could be forced to do so, but enforcement of investments in new power generation probably might only lead to their postponement, instead of the investments that are needed. *Some kind of carbon pricing*, - either by emission trading or taxing, should therefore be an essential element of the policy package of this part of the curve.
- Options at the right hand side of the curve are more expensive but essential as part of an innovation approach as it is expected that they will become cheaper in the future. Very high CO_2 prices or taxes would be needed to incentivise solar-PV at this moment. Differences in costs in this part of the curve are large: the costs of onshore wind, offshore wind or solar PV differ considerably. Therefore, *more specific technology* approaches are needed, in which technology development, joint learning and cost decrease are important elements.

Of course, these are only rough sketches of the basic elements of the policy package. In reality, only policy packages are feasible. Sometimes, a 'best option' is politically out of reach and 'second best' options are feasible alternatives. Due to deployment of new technologies costs go down and alternatively, due to increasing scarcities and geopolitical realities costs of conventional fuels might go up. In this way the real cost curve is a dynamic phenomenon, not a static one. And finally, governments will always try to create stable conditions for investors, but policy instruments will change over time due to new insights and new circumstances.

The real world is full of uncertainty. We do not know whether and to which extent energy prices will increase or decrease in the near future, or whether deployment of new technologies in other parts of the world will grow more or less than in Europe. Relative confidence about some basic trends is justified and in the analysis some firm assumptions have been made that are a reasonable starting point of the approach. A main example of the latter is the assumption that - although not starting at the same moment and with the same initial strength - a parallel process aiming at energy security and sustainability will take place in all major economies. Because it is assumed this will happen, eventually a global investment in clean technologies will take place and as a result costs will decrease. To get a robust picture, ECF developed several pathways. All

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[7] It has been analysed in-depth which types of policy instruments make sense in which situations. Generally, regulatory instruments are preferred when enforcement is expensive and it is considered to be essential that the target is met. A trade-off between commitment and flexibility exists. Economic instruments are preferred in case of uncertainty, information problems and when the costs of response vary between entities. Cap-and-trade mechanisms combine regulation (the cap) and economy (the price). For an introduction, see C. Hepburn (2009).

of them are able to deliver a zero-carbon power system. In many respects, the similarities of a European power system with 60% or 80% renewable energy are much larger than the differences. But the exact amount of transmission that is needed differs and the level of internal interdependencies within Europe differs. The policy approach has to be robust enough to deal with this type of uncertainty.

In this document, a division has been made between ETS sectors (power generation and energy intensive industry, Chapters 2-5) and non-ETS sectors (buildings, smaller companies, most transport, Chapters 6-8). The ETS sectors have an emission cap, whereas non-ETS sectors don't have one. As the power sector is the main subject of the report, it has been looked at from different angles: how to strengthen the cap (Chapter 2), how to improve specific technologies (Chapter 3), the market design of generation (Chapter 4) and infrastructure (Chapter 5).

Chapter 2 outlines how the EU ETS system can be improved and strengthened to reach a fully decarbonised power sector in 2050. In theory, due to a firm cap, this instrument will deliver a solid base for both timely retirement of high-carbon assets and long-term investments in carbon reducing technologies. However, the actual rate of greenhouse gas reduction implied in the revised EU ETS Directive is not stringent enough to attain a more or less zero-carbon power system in 2050. Hence, an important recommendation of Chapter 2 is to enhance the annual greenhouse gas reduction rate of the EU ETS cap, preferably starting from 2013 onwards. In addition, the chapter considers other options to improve the performance of the scheme and, finally, analyses the interaction between emissions trading and other policy instruments, in particular to encourage long-term investments in low carbon technologies such as CCS.

Chapter 3 deals with technology. European member states are actively involved in technology-specific measures. Whereas a carbon price is a technology neutral instrument, technology-specific approaches by definition make choices. These choices have two meanings. On the one hand, they aim at keeping options open. This is the case in R&D policies where different technologies in early stages are looked at. As R&D, compared with deployment activities, is relatively cheap, Europe can afford to investigate many different new approaches. This is the arena of the technology institutes, the European Energy Research Alliance (EERA) and universities for more fundamental research. At a certain moment choices are and have to be made, however. Countries decide how much subsidy they want to spend on different renewable energy technologies, or which kind of 'banding' ('double counting') is accepted in green certificates. Implicitly, the reason they think this makes sense is that they rely on the learning rates of these technologies: in case of currently relatively high costs, it is expected that costs will go down with larger deployment. A clear example of this approach is solar PV. It is expected that this kind of technology will become more and more competitive and at a certain moment the specific stimulus may end. It is uncertain when this is the case and Chapter 3 discusses how this uncertainty can be dealt with. Additionally, clean energy technologies have become part of industrial policies. This is not only valid for renewable energy, but also for the second type of zero-carbon technology; fossil fuel generation combined with carbon capture and storage (CCS). A third technology specific approach is taken in the EU member countries with regard to nuclear energy. Not all EU member countries have opted for these two options, but in the overall European approach they play an important role.

Chapters 4 and 5 deal with the market design of the power sector; first with regard to generation (Chapter 4) and next with regard to infrastructure (Chapter 5). These issues are strongly related, but their context is different. Generation is an issue of energy markets, infrastructure is a regulated monopoly. Volume 1 showed that a zero carbon power system will be more capital intensive and more inter-regional. EU member states are expected to gradually start making use of comparative advantages (solar in the South, wind in the West), intermittency issues become more important and a joint European approach will be relatively cost-effective. Separate national approaches will be much more costly and probably even impossible. To some extent several policy questions of generation and infrastructure will converge. This issue will be looked at from several angles: the need to combine market investments with a kind of indicative planning to ensure optimal interaction between infrastructure and generation; regulators need an extended mandate, in which sustainability, security of supply and a European approach are as important as the relatively short-term national approaches that have been so successful up to now; new transmission lines have to be financed and smart grids have to develop, starting with pilots and enabled by forward-looking regulation. Without promising business cases, investments will not be made. Finally, the high capital intensity of the future clean power market in all probability will lead to more volatile prices and higher risks for investors. It is uncertain what might be the best way to deal with this change. To some extent it is a rather fundamental change of those power market tendencies that have emerged in the last two decades, in which relatively low capital intensive options have been preferred. The short term has often been preferred over the long term and competition effectively was the most important starting point in the considerations of market design. This has provided great benefits. It is uncertain what might be the best way to deal with these new challenges. It is highly plausible that gradual changes in the actual system would be insufficient. More plausible is the case that could be made for the need of fundamental additions to the actual design of the power market, but uncertain is which shape they will take and how soon they will need to be fully operational. Much can be learned from experiences elsewhere, the United States, Latin America. It will be suggested that thoughtful considerations are needed to be prepared on time for the eventual introduction of new market designs.

As the ECF analysis mainly looks at the power sector, the policy instruments that are needed to enable the huge changes in this arena have been looked at with reasonable depth. Some interactions with other sectors, i.e. buildings and passenger transport, have to be investigated as a decarbonisation of the power sector enables these sectors to become much cleaner. Moreover, without substantially more energy efficiency and flexibility in these other sectors, considerably more power production would have been necessary. This is the topic of *Chapters 6 and 7.*

Chapter 6 investigates which energy efficiency policy instruments are actually used at the European level, which challenges exist and which next steps can be taken. As stated earlier, cost-effective regulation is the policy backbone of the drive towards more energy efficiency (smart standards), but this could be done in such a way that it will stimulate more innovative: zero emission buildings and energy passive houses. A smart grid will be the physical backbone of this approach and has been looked at in Chapter 5.

Chapter 7 deals with transport. The main focus is put on road transport, as this will gradually lead to a closer interaction with a cleaner power system, either via battery electric vehicles or more indirectly by means of fuel cell electric vehicles. Much is uncertain in this respect and therefore joint learning by means of demonstrations, pilots and common standards is essential. This policy push has to be connected with a policy pull of more stringent standards, driving higher energy efficiency and cleaner cars.

There is no long-term basis against which industries can plan investment in energy efficiency and build the supply chain capability required to ensure the necessary ongoing improvements are delivered. In *Chapter 8*, it is suggested to consider the introduction of a European Climate and Resource Directive in which European member states commit themselves to considerable greenhouse gas reductions in non-ETS sectors by 2050. In this way a stable policy environment will be created, possibly diminishing uncertainty and creating a better business case for investments in enabling infrastructure.

2. Roadmap 2050: policy implications for the EU ETS and whether additional instruments have to be considered

2.1 Introduction

The actual main driver of greenhouse gas emission reduction in the power sector is the European emissions trading system (EU ETS). The aim of this chapter is to outline and discuss the role of the EU ETS in achieving the overall target of the *Roadmap 2050* strategy in general and the decarbonisation of the power sector in particular and to discuss improvements of the ETS and the question whether additional policy instruments have to be considered. Section 2.2 presents the overall framework of the EU ETS in order to achieve this target, while Section 2.3 discusses some implications for the EU ETS in the short and medium term, i.e. up to 2020. Finally, Section 2.4 addresses the interaction between the EU ETS and other policy instruments, in particular to stimulate long-term investments in carbon saving technologies such as CCS and timely retirement of existing high-carbon assets.

2.2 General, long-term framework of the EU ETS

Assumptions

It is assumed that the EU ETS remains a key CO_2 reduction policy instrument for those EU sectors covering large emitters, i.e. in particular the power and energy-intensive, industrial sectors. The EU has invested much 'political capital' in developing this instrument, it can be environmentally and economically effective, experience has been gained and improvements were made in the recent past. In addition, it is assumed that, besides the EU, other developed countries and emerging economies will accept comparable long-term mitigation commitments as the EU, i.e. reducing overall GHG emissions in 2050 by some 80% compared to 1990. The implications of this target, and the assumptions mentioned above, for the basic features and performance of the EU ETS are outlined below.

Coverage

The sectoral and GHG coverage of the EU ETS up to 2050 remains basically the same as the scope of the EU ETS Directive beyond 2012, i.e. predominantly CO_2 emissions from the power sector, aviation, and specific energy-intensive industries, including some non-CO_2 GHG emissions from these industries.[8] Possible extensions include carbon emissions from shipping, rail transport and (all) other non-CO_2 GHG of participating installations, if they can be cost-effectively monitored and verified (see also Chapter 7).

Cap

The revised EU ETS Directive has specified the annual caps of EU emission allowances for the third trading period (2013-2020) and beyond, i.e. the linear factor by which the annual amount of EU allowances (EUAs) shall decrease is 1.74% in relation to the average cap for the second phase (about 2 $GtCO_2$ equivalents of EUAs per year over the period 2008-2012).[9] This linear reduction factor may be revised by 2025 at the latest. It is based on the EU objective to reduce its overall GHG emissions by at least 20% in 2020, compared to 1990.

A remark has to be made with regard to the target. The ambition of the *Roadmap 2050* project is to attain a nearly fully decarbonised power sector by 2050. As other mitigation studies show, the

[8] The national coverage of the EU ETS, however, will of course expand if other, new Member States join the EU.
[9] Note that the absolute cap will be adjusted to changes in the coverage of the EU ETS accordingly, while the annual reduction factor will remain basically the same.

power sector is assumed to implement essentially carbon free technologies. By 2050, 95% is assumed to be possible (ECF, Volume 1). It is assumed that CCS power plants will continue to emit some CO_2 (only 90% is assumed to be captured) and probably highly flexible open gas-cycle turbines (OCGT) remain needed for system balancing.[10] In industry, however, meeting a similar emission reduction is much harder. The technical analysis has assumed a large share of efficiency improvements to be possible, a rollout of CCS is possible, covering 50% of heavy industry in Europe, but potential breakthroughs in industry are left out. In this way the McKinsey Global GHG Abatement Cost Curve has indicated that a cost effective abatement approach to both sectors would lead to a 95% GHG emissions reduction in the power sector and 40% in industry. Furthermore, the technical analysis of the *Roadmap 2050* project shows that reductions in the power sector have a positive external effect: only by means of nearly zero carbon emissions in the power sector can large reductions in road transport and the residential sectors be enabled. Industrial sectors do not have this external effect.

These considerations have implications. The EU ETS does not only cover power generation, but also includes energy-specific industries and aviation. This makes sense, as the more emissions are included in the cap, the better it is from a point of view of emissions reduction and economic efficiency of the scheme. However, when the desired 2050 emission reductions differ in the sub-sectors, differentiation may need to be considered in the ETS. The ambition of the current project is to attain a largely zero carbon power generation by 2050, whereas emissions reduction in industrial sectors is expected to be less. From a specific viewpoint of emissions reduction this does not matter, as all greenhouse gas emission reductions are equal no matter where they originate from. However, as currently the ETS is regulated by one EU-wide, ETS-wide cap, the attribution of a zero-carbon target for the electricity sector becomes difficult.

In theory this could be solved by introducing different emissions caps for industry and power. However, this will reduce liquidity of the system and lead to more uncertainty and increase volatility of prices. Therefore additional instruments need serious consideration to allow the power sector to realise the decarbonisation goal. At the same time it has to be analysed to which extent further reductions in industry are feasible than currently assumed in Volume 1: on closer inspection more opportunities might be available in industry than have been assumed.

In order to achieve the overall *Roadmap 2050* target in general and the 2050 mitigation target for the power/other ETS sectors in particular, this mitigation factor has to be intensified. This could be done in the following way. It is based on the willingness of the EU to increase its overall GHG reduction target to 30% by 2020, compared to 1990, if other developed and emerging economies commit to comparable mitigation targets as part of the ongoing 'Copenhagen process' to reach agreement on these targets. This scenario would imply that, depending on the additional burden sharing between the ETS and non-ETS sectors, the annual reduction factor for the ETS over the years 2010-2020 has to be increased by approximately 1%, i.e. from 1.74% to, say, 2.75%[11]. To succeed in defining an effective long-term pathway, the EU is recommended to agree with an overall greenhouse gas emission reduction target of 30% compared to 1990, implying an annual reduction of EU ETS emissions by 2.75% over the period 2013-2020.[12]

The EU should opt for this approach, for the following four reasons. First, it would give a strong signal, both internally and externally, that the EU is taking its responsibility and leadership in reducing GHG emissions seriously. Second, it would result in higher ETS reduction targets and correspondingly higher EUA carbon prices in the short and medium term compared with a pathway without a tightening of the cap, thereby encouraging long-term investments in R&D

[10] An option not explored in ECF Volume 1 is to use biomass CCS plants to bridge the gap and make the power sector completely carbon free.

[11] The annual mitigation factor is related to the average cap for the second trading period of the EU ETS, 2008-2012.

[12] To reach full decarbonisation of the ETS sectors, it could be reduced to about 2.42% in the period 2020-2050. As mentioned, according to current assumptions, a full decarbonisation of industry is not necessary in the *Roadmap 2050*, partly because it has not been analysed in such depth as opportunities in the power sector.

and carbon saving technologies in ETS sectors. Third, the overall EU reduction target of 20% in 2020, and the corresponding annual reduction factor of 1.74% for the ETS sectors, have been decided in 2008, i.e. based largely on expectations of GHG growth trends before the current economic crisis. Due to this crisis, however, both present and expected ETS emissions have decreased significantly and it is suggested by leading economists that to some extent the reduction in GDP has a permanent character. Hence, achieving the 30% target can now be reached at costs that are probably largely similar to the cost expectations in 2008 based on the 20% reduction proposal. Finally, if the EU is interested in a large measure of decarbonisation of the ETS sectors in 2050, the suggested approach would result in a more balanced mitigation pathway than in a situation in which a strengthening of the mitigation factor is postponed.

Trajectory
To reduce uncertainty, the trajectory of emissions reduction can be made much clearer. Transparency in annual absolute amounts of emissions in the periods that are relevant for current investment decisions - not only 2020, but also 2030, 2040 and 2050 - have to be provided. This is only feasible with a clear view on the conditions that have to be met to make the long-term targets acceptable. The ECF pathways have shown that this may be done without risk of security of supply and against reasonable costs (compare Chapters 3 and 4). This process, however, will take time.

Allocation
By 2020, the power sector in all EU countries has to purchase all of its required emissions allowances (EUAs) at an auction or market, while other ETS sectors may still receive (a major part of) their EUAs for free in order to avoid loss of industrial competitiveness and carbon leakage to countries facing less - or no - abatement costs due to a lack of comparable mitigation policies in these countries. Resulting from the assumption, however, that other developed countries and emerging economies will accept similar long-term, ambitious mitigation commitments as the EU, there is less justification for continuing free allocations to industrial sectors beyond 2020. Therefore, free allocation beyond 2020 should, in principle, be fully abolished in order to provide the right incentives for carbon saving investments and to avoid the risk of windfall profits (due to selling over-allocations and/or passing through the opportunity costs of free EUAs to output prices). In case, EU industries beyond 2020 are still faced by unfair competition due to unequal mitigation policies of outside countries, the EU could consider to replace free allocations to vulnerable industries by a system of border tax adjustments (to be agreed and controlled within the context of the WTO/UNFCCC).

Banking and borrowing
For the second and subsequent trading periods of the EU ETS, EUAs are allowed to be banked from one period to the next. This implies that, in theory, there will be a uniform (discounted) EUA price over the period 2021-2050. In practice, however, changes and fluctuations in this price are very likely due to uncertainties, i.e. lack of perfect foresight and resulting unforeseen outcomes in underlying EUA price determinants. In addition, it implies that, due to banking, ETS emissions in early years will be lower than the corresponding annual caps, while emissions in later years will be higher and, hence, the power/other trading sectors may *de facto* not be fully decarbonised in 2050.

Borrowing of EUAs, on the other hand, is not allowed and probably less relevant as the ambitiously decreasing annual caps will tend to result in increasing marginal abatement costs - and, hence, corresponding EUA prices - rather than, on balance, decreasing costs/prices due to technological innovation and learning.

Linking with other emissions trading and crediting systems
Over the coming years/decades, the EU ETS may be linked to an increasing number of comparable (cap-and-trade) schemes in other countries and regions. Depending on the specific conditions, in particular whether allowance trading among the linked ETSs is fully unrestricted or not,

linking will result in higher overall carbon efficiency (lower total abatement costs), higher market liquidity (more price stabilisation) and a convergence towards a uniform carbon price across the linked ETSs. Linking, however, sets certain restrictions or harmonisation conditions to the design/change of specific ETS features, e.g. the introduction or adjustment of a price floor/ceiling (see below), as it affects not only the performance of specific features of an individual ETS but also of all other linked ETSs.

Linking of the EU ETS to the CDM or other crediting systems is proposed to be reduced/limited to a relatively low percentage, e.g. 5-10%, of total required emissions reductions beyond 2020, assuming that (i) other, linked ETSs will have similar crediting conditions, and (ii) other major (high emitting) countries have accepted comparable ambitious mitigation targets and, hence, the opportunities for buying 'cheap' external credits is limited anyhow. Moreover, in order to avoid carbon leakage through offset projects, it is important that credits from such projects used by ETS operators represent real verifiable, additional and permanent emission reductions and have clear sustainable development benefits and no significant negative environmental or social impacts (EC, 2009a).

Depending on the extent to which linking of the EU ETS to the CDM or other crediting systems will be allowed, however, it will result in a lower EUA price as well as in lower overall abatement costs for the EU. On the other hand, it implies that the power/other trading sectors may *de facto* not be fully (or nearly fully) decarbonised in 2050.

To conclude, the tightening of the cap and limitation of CDM will contribute to a higher price of emissions allowances. In theory, the actual annual reduction factor, combined with the tightening up to 2020, could lead to deep emissions cuts in the power sector, as the marginal abatement options in power generation are less expensive than in industrial sectors.

Price floor and ceiling

The EU could consider implementing a price floor/ceiling into its ETS. The principal argument for a EUA price floor is that it reduces the CO_2 price uncertainty for long-term investments in carbon-saving innovations, which is the reason it has been suggested by both energy experts and official advisory bodies (see Ofgem, 2010).). Basically, there are three options to effectuate a price floor in an ETS (Wood and Jontzo, 2009):

- Buying back EUAs by a public authority, thereby reducing the amount of EUAs and lifting the EUA price to the floor level.
- A reserve price when EUAs are auctioned, again limiting the amount of EUAs available to emitters (Grubb, 2009).
- Emitters have to pay an extra fee (or tax) for each tonne of CO_2 emitted, in addition to having to present a permit. The effective carbon price then becomes equal to the sum of the permit price and the extra fee. Within this option, there are two sub-options:
  - A fixed tax level.
  - A variable tax level, depending on the EUA price.[13]

The major effects of an EUA price floor are that it (i) enhances both total emission reductions and costs, and (ii) reduces the carbon price uncertainty for CO_2 mitigation investments and, hence, may encourage such investments.

The principal argument for a price ceiling, or 'safety valve', is that it limits the risks of (unexpectedly) high abatement costs and, hence, enhances the willingness to accept more ambitious mitigation targets. This applies notably if (i) future, long term abatement costs are highly uncertain, e.g. due to high uncertainties on future technological innovation and learning, (ii) long-

[13] As argued below, a carbon price in addition to the EU ETS, reduces the EUA price while the total domestic carbon price (ETS + tax) may either be unaffected or increase (up to the tax level), depending on the geographical or (inter)national coverage of the carbon tax. See also Wood and Jontzo (2009).

term mitigation targets are very ambitious, as is the case for *Roadmap 2050*, and (iii) the opportunities for using (cheaper) external offset credits are limited.

In principle there are two basic options to effectuate an EUA ceiling price:

- Once the EUA price reaches its specified ceiling level, a public authority starts selling additional allowances.
- For each tonne of CO_2, an emitter has the option of paying a carbon tax, fixed at a certain level, rather than surrendering an EUA, implying that the carbon tax level will function as a EUA price ceiling.

In addition to effectuating an EUA ceiling price, both options have basically similar other effects. They both result in additional public revenues, which might be used to reduce (future) abatement costs of promising or learning technologies. On the other hand, both options result in higher emissions and, hence, introducing a ceiling price implies less certainty that a mitigation target will be met (i.e. actually price/cost uncertainty is partially shifted towards quantity uncertainty). This may be justified from a cost-benefit or welfare point of view, including the consideration that additional emission reductions may be shifted to future periods when abatement costs might be lower owing to technological innovation and learning.

The introduction or setting of an EUA price floor/ceiling, however, raises also some objections, challenges or other problems.[14] Firstly, neither the current EU ETS Directive up to 2012 nor the recently revised Directive starting from 2013 includes the opportunity of launching a price floor/ceiling, while revising the Directive once again, and including this opportunity, would most likely become effective only starting from 2020 at the earliest due to reasons of political feasibility, time-consuming legislation procedures, market stability, and policy consistency and credibility.

Secondly, in general, several policy makers and ETS participants are against almost any EUA price intervention, while some parties are opposed either to floor prices, notably energy and industrial stakeholders, or to ceiling prices, especially environmental groups. Hence, it may be difficult to reach political agreement on a system of EUA price floors/ceilings and to change the ETS Directive accordingly.

A third, related and practical problem is how to set and effectuate a system of EUA price floors/ceilings. While some argue for high and rising floor prices and relatively high (or even no) ceiling prices, others are in favour of low, stable (or even no) floor prices and relatively low ceiling prices. Moreover, a system of EUA price floors/ceilings can be effectuated by different mechanisms and institutions, e.g. by imposing a minimum/maximum CO_2 tax level in stead of the EU ETS or by buying/selling emission allowances at a certain carbon price level, with each mechanism having its budgetary implications or other pros and cons (Philibert, 2008; Helm, 2008 and 2009; Wood and Jones, 2009; and Grubb, 2009).

A major problem of EUA price stabilisation is that the long-term market equilibrium EUA price is, by definition, unknown and uncertain. Setting the price floor/ceiling either too high or too low, or setting the price band too narrow, may result in serious risks and problems in terms of budgetary implications, economic costs, abatement inefficiencies and/or meeting mitigation targets. To some extent, these risks and problems can be reduced by setting a relatively wide price band, starting from relatively low price levels, which may increase by a certain percentage over time and which may be adjusted every five or ten years, depending on the trend of the EUA market price. It should be realised, however, that to some extent there is always a trade-off be-

[14] For a more extensive discussion of price floors/ceilings under emissions trading - including arguments pro and contra, mechanisms and problems involved - see, among others, Philibert (2008), Helm (2008 and 2009b), Wood and Jotzo (2009), and Grubb (2009).

tween the level of EUA price certainty on the one hand and the problems and risks of price stabilisation on the other.

A fourth and final set of problems refers to the case of linking between different emissions trading schemes (ETSs). Depending on the specifics of linking - in particular the level of free trading of allowances - such a case requires a certain harmonisation of carbon price floors/ceilings between the schemes involved. Otherwise, the carbon price may be set effectively by the ETS with the lowest price floor/ceiling, with related implications in terms of budgetary impacts and abatement efficiency for the countries of the linked schemes concerned. Hence, whereas linking ETSs may result in greater market liquidity and, hence, in more carbon price stability, i.e. less price uncertainty, the problems and risks of further enhancing price certainty by means of a system of price floors/ceilings may increase due to linking.

To conclude, there are sound arguments for introducing an EUA price floor/ceiling in the EU ETS but it also raises a variety of risks, challenges and other problems. Therefore, the European Commission could consider to (i) conduct a serious, independent study on the extent to which EUA price instability/uncertainty is a problem for the long-term environmental and cost effectiveness of the scheme and, if yes, whether and how this issue could be addressed by a system of price floors/ceilings, (ii) consult a variety of stakeholders and experts on the issue of EUA price stabilisation, and (iii) based on (i) and (ii), decide and propose whether and how a EUA price floor/ceiling could be introduced as part of the EU ETS.

2.3 Implications for the EU ETS up to 2020

In January 2008, as part of its overall energy and climate policy package, the European Commission proposed a revised EU ETS Directive for the period beyond 2012, which was adopted by both the European Council and Parliament in December 2008. For the third trading period, 2013-2020, this Directive aims at an emissions reduction in ETS sectors of 21% in 2020, compared to 2005, and sets annually declining caps to achieve this target, including the option to use limited amounts of JI/CDM credits. At the time this Directive was launched and discussed, early-mid 2008, the EUA price was expected to amount to approximately 30-40 €/tCO_2 in 2020, accounting for the effects of renewables and other (energy efficiency) policies on ETS emissions and EUA prices.

More recently, however, due to the (unexpectedly) severe economic crisis, both actual realisations and expectations of ETS carbon emissions/prices have been reduced significantly. The current EUA price fluctuates at a level of 15 €/tCO_2, while it is expected that the average EUA price may only slight increase over the coming years to a level of about 20 €/t in 2020.

The current economic conditions do not affect meeting the EU ETS mitigation target up to 2020. On the contrary, they facilitate the achievement of this target, including some potential additional emission reduction due to the option of banking. Moreover, beyond 2020, the EU ETS can contribute to meeting the long-term mitigation target of *Roadmap 2050* by setting the cap and inducing future EUA prices accordingly. Nevertheless, there is a legitimate concern that the current and expected EUA price up to 2020 may not provide the correct signal for long-term investments in carbon saving technologies in order to meet more ambitious mitigation targets over the period 2020-2050. Or, to put it slightly different, a possible shortcoming of the present EU ETS might be that, although more or less by definition it will meet its mitigation target up to 2020 by fixing the cap and inducing EUA pricing accordingly, it may not provide the right price incentive for low-carbon investments to achieve more ambitious abatement commitments beyond 2020.

Some qualifications, however, can be added to the role of current and short term EUA pricing for long-term investments in carbon saving innovations. Firstly, it is probably correct that the current EUA price may not provide a good indicator for long-term, future carbon prices and, hence, not a good basis for decisions on long-term investments in carbon mitigation technologies (similar to other current prices for other types of long-term investment decisions). In general, however, such decisions are based, among others, on future, long-term (carbon) price expectations, although in case of the EU ETS, the empirical evidence on which these decisions/expectations are based is still limited, anecdotic and often contradictory.

Secondly, in contrast to a carbon tax, the price or costs of a tonne of CO_2 is uncertain within an ETS while the cap or amount of emissions over a certain period is given. Hence, within an ETS, long-term decisions on low-carbon investments are most likely less based on current or uncertain, future prices but rather on the certainty of the cap, which in case of the EU ETS has indeed been specified for a long-term period.

Thirdly, the role of carbon pricing in inducing long-term investments in carbon-saving innovations may be important or even decisive in the full deployment or commercialisation phase of a technology but less relevant in the preceding research, development and demonstration phases. Actually, an ETS or carbon price can only cope with the CO_2 cost externality of technology while all other constraints, barriers or market failures of environmental innovations in their respective technology development phases have to be addressed by other, additional policy measures (see Chapter 3).

Nevertheless, with these qualifications in mind, a variety of options could be considered to reduce the risks of currently low and uncertain EUA prices for long-term investments in low-carbon technologies. In particular, these options include (CCC, 2009):
- Options to strengthen the EUA price signal.
- Options to provide confidence over the price/support received by low-carbon production.
- Other options, e.g. regulation, to ensure investments in low-carbon technology.

While the first category of options is evaluated briefly below, the second and third categories are discussed in Section 2.4 as part of the discussion of the interaction of the EU ETS and other policy instruments. The evaluation of the options below is based on some criteria, including:
- The extent to which the options interact with the central objectives of the scheme or, more particularly, the extent to which the options affect the environmental and cost effectiveness of the scheme, including how to deal with uncertainty.
- The interaction with the investment cycle in capital-intensive capacities that has to be taken into account.
- The extent to which the options fit with the revised EU ETS Directive beyond 2012.
- The extent to which the options affect the credibility and reliability of the scheme, notably among EUA market participants and other ETS stakeholders.

Options to strengthen the EUA price signal

In theory, there are some options to strengthen, i.e. increase the EUA price in the short or medium term such as lowering the cap or reducing the opportunities to use JI/CDM credits to meet ETS compliance, including cap decreasing options such as cancelling allowances in the New Entrants Reserve or auctioning less allowances than announced. Although the economic recession offers some ground for considering such options, in practice, however, these options do not fit with the current and revised EU ETS Directives, while changing these directives and, subsequently, implementing these options would either be politically unfeasible, time consuming or, more importantly, reduce the political credibility and reliability of the scheme among the EUA market participants and other stakeholders.

The only major exception in this field would be the already announced option - included in the revised EU ETS Directive - to increase the overall EU mitigation target from 20 to 30% in 2020, compared to 1990 GHG levels, as part of the outcome of the Copenhagen process towards a new global climate treaty. Depending on the evaluation of this outcome and eventual follow-up decisions on sharing the additional EU mitigation burden between external offsets and domestic reductions by ETS versus non-ETS sectors, using this option would normally imply a significant reduction of the supply of EUAs up to 2020 and beyond. Hence, due to the possibility of banking allowances, this option would imply a significant increase in the EUA price once this reduction of the cap is indeed expected.

Another implication, depending on the evaluation of the outcome of the Copenhagen process, might be that the European Commission decides to reduce the amount of free allocations to industrial installations as they might be less vulnerable to carbon leakage and loss of competitiveness in case of a new worldwide climate agreement. Both a higher EUA price and less free allocations to new industrial entrants or, even better, full auctioning for all new entrants in both the energy and industrial ETS sectors would mean a stronger incentive for long-term investments in carbon reducing technologies in these sectors. According to the revised EU ETS Directive (EC, 2009a), the Commission should review the situation by 30 June 2010, consult with all relevant social partners, and, in the light of the outcome of the Copenhagen process, submit a report accompanied by any appropriate proposals, including - among others - possible implications for the EU ETS cap and the amount of free allocations to industrial operators.

In case the evaluation of the outcome of the Copenhagen process does not offer the opportunity to reduce the amount of EUAs up to 2020 and beyond, there are at least, in theory, two other options to strengthen the carbon price signal within the ETS. As discussed above, one option is to introduce an EUA price floor as soon as possible. This option, however, does not fit with the present/revised ETS Directive and, in addition, would reduce the political credibility and reliability of the scheme among its stakeholders. In general, as noted, both policy makers and market participants are against any EUA price intervention, if not specified in the Directive, and do not favour any EUA price floor/ceiling in particular. Hence, the feasibility of introducing an EUA floor price in the short to medium term, if ever, is most likely rather low.

A second, related option is to introduce a carbon tax in addition to the EU ETS. One of the advantages of this option would be that it does not require an uncertain and time-consuming process of adjusting the EU ETS Directive, although it probably still interferes with the policy expectations of ETS stakeholders and, hence, may reduce their confidence in the scheme and climate policy in general. On the other hand, as shown by the EU experiences in the 1990s, it is very hard and almost unfeasible to introduce an EU-wide carbon tax at an effective level for ETS sectors, in particular for energy-intensive industries that are vulnerable to external competition. Moreover, even if it would be possible to introduce an EU-wide carbon tax for the ETS sectors, in addition to the scheme, it would reduce - or even nullify - the EUA price and, hence, the effectiveness of the ETS assuming, as argued above, that it is not possible to lower the cap accordingly.[15]

Another advantage of a carbon tax, however, is that, in principle, it could be introduced at the national and/or sectoral level, thereby avoiding the political problems of introducing an EU27-wide tax and/or raising costs for energy-intensive industries sensitive to outside competition. This specific option, however, would be even less effective in the ETS sectors than the general option discussed above, i.e. it would reduce the EUA price, while only shifting emissions across ETS sectors/countries. In addition, it may reduce the industrial competitiveness of those countries introducing such a tax, depending on the sectoral coverage of the tax and the vulnerability of the covered sectors to external competition. Hence, the introduction of a carbon tax in addition to the EU ETS does not seem to be feasible and/or effective for the ETS sectors.

[15] On the other hand, if it would be possible to lower the cap in the short or medium term, the introduction of a carbon tax next to the EU ETS hardly makes any sense and should, therefore, be highly questioned (see Section 2.4 below).

To conclude, the only real option to strengthen the EUA price signal in the short to medium term seems to be to reduce the ETS cap towards 2020 as part of the outcome of the Copenhagen process to reach a new global agreement to address climate change. The COP-15 Conference in Copenhagen is perceived as having ended in a disappointing result. The implications for the GHG mitigation target of the EU up to 2020, however, are still unclear and it has been argued in the ECF Volume 1 report and this Working Document that strong arguments exist to reduce the cap. It may take up to 30 June 2010 at the latest before the Commission sets out the possible implications of the Copenhagen process for the EU ETS during its third trading period (2013-2020), including the level of the cap and the amount of free allocations to industrial operators.

Nevertheless, regardless the possible implications of the Copenhagen process for the EU ETS in general and the EUA price signal in particular, there are some other options which might be considered to reduce the risks of currently low and uncertain EUA prices for long-term investments in low-carbon technologies. These options are discussed briefly in the next section.

2.4 Interaction of the EU ETS with other policy instruments

General considerations[16]
A defining feature of an emissions 'cap-and-trade' system, such as the EU ETS, is that, assuming adequate monitoring and enforcement, there is theoretical certainty that total covered emissions will be equal to the aggregate cap and, hence, that the environmental effectiveness of the scheme is guaranteed[17]. A second feature is that, under a standard set of assumptions regarding the competitive operation of the carbon and other relevant markets, the scheme will result in the target to be met in the most cost-effective way as the marginal abatement costs across participating sources will be equalised to the carbon allowance price. The second feature assumes full insight into future developments and no or little uncertainty in technology or the nature of the business cycle, or lock-ins in investments that with hindsight knowledge did not offer the benefits expected upfront.

These idealised features of a cap-and-trade system have important implications for the coexistence or interaction with other, additional policy instruments. To the extent in which the assumptions are valid, they imply that the use of a second carbon mitigation instrument that directly or indirectly interacts with the ETS will increase the overall costs of meeting the cap while at the same time having no influence on the environmental effectiveness of the scheme, i.e. on the assurance of meeting the cap.

However, it is uncertain to which extent these assumptions *are* valid. This is related especially to lack of information with companies, to intrinsic uncertainties and to the impact of business cycles in a capital-intensive sector like power generation. If the ETS is properly upheld, the realisation of the cap is guaranteed, but the price is an uncertain result of supply and demand of emissions allowances, and of relevant expectations. Almost nobody had expected the current economic crisis and with the knowledge of today the emissions cap probably would have been set differently. Investments in capital-intensive sectors like power generation (but not different from industrial sectors such as refineries, chemicals and steel industry) are highly cyclical. In reality one cannot expect one linear path of emissions reduction as the standard model assumes. In a time of low economic growth, power demand will be low, EUA prices will be low and investments tend to stagnate. When economic conditions improve, power demand increases, the EUA price increases, and fuel switch takes place in actual decisions on how to produce. Investment decisions are not able to react quickly to (market and EUA) prices, due to permit proce-

[16] These considerations make use of part of the ideas expressed in Sorrell and Sijm (2003), Sorrell et al. (2003), Sijm and Sorrell (2004), and Sijm (2005). For more recent publications on the interaction between emissions trading and other policy instruments see, among others, Abrell and Weight (2008), de Jonghe (2009), Blyth et al. (2009), and del Rio (2009).
[17] However, it does not guarantee the reduction to be met in the region itself, due to mechanisms such as CDM.

dures, long gestation periods and probably insufficient capacity of transmission grids. After several years - maybe 5 or more - new, clean capacity is ready to produce, exactly at the time economic growth might begin to decline. These factors lead to risk aversion by investors and inhibit the ideal functioning of an ETS.

This leads to three preliminary conclusions:
- It could be useful to look at ways in which these uncertainties may be diminished.
- There may be a benefit in striving for combinations of EU ETS and other instruments, especially in the power sector with its potential positive external effects as mentioned before. Careful analysis is needed, however.
- The uncertainties are mainly related to investments and less to operational production decisions.

A potential reduction of uncertainties has several aspects. It might be considered whether the general framework of the electricity market is still fit for purpose to deliver the necessary investments that are needed to attain a capital stock that is highly capital-intensive but will tend to produce against low marginal costs. This is the subject of Chapter 4. Another issue is the political uncertainty: as long as investors do not know which political framework might be expected, production costs could be higher than with better foresight. The IEA has tried to estimate the costs of uncertainty about policy in a low-carbon context. The risk premiums of uncertainty about changes in climate regulation in the short-term (1-3 years) appear to be much larger than risk premiums created by fuel price uncertainty (IEA, 2007b). IEA's conclusion was that it is important to announce in advance which path of carbon reduction has to be followed. This has been done in the EU and, by tightening the cap in 2020 as proposed in this report, the target would become more reliable as a beacon on the path towards deep emissions cuts.

In addition to the measures in the ETS, it could also be argued that a package of policy instruments might further improve certainty. This is not evidently true, however. An EU Directive, such as the emissions trading policy framework, is legally a strong instrument as it can be changed only by joint EU decision. On the other hand, a patchwork of different incentives and regulations in different Member States might lead to even more uncertainty. It might be concluded that it is not evident which approach will reduce uncertainty about future policies most, but at least a clear European statement about the target it wants to reach and intermediate steps that are necessary, is a necessary element. This subject will be further looked at in Chapters 4 and 5 in which a potential policy instrument of developing Roadmaps of power generation and infrastructure investment will be looked at.

To conclude, markets may only partially approximate the theoretical ideal outlined above. Market failures are usually widespread in these markets, in particular in the markets for energy efficiency and carbon saving technologies (Sijm, 2004). Moreover, the social or political process that leads to the setting of the ETS cap - and its corresponding carbon price - is unlikely to provide an adequate reflection of the 'social optimum' for carbon externalities (to the extent that such a concept is meaningful for global climate change). In addition, governments have objectives which go beyond carbon efficiency, such as the promotion of energy security, industrial employment or social equity. In these circumstances, there can be legitimate grounds for introducing or maintaining other policy instruments that directly or indirectly interact with the ETS. These include:
- Improving the static efficiency of the ETS by overcoming market failures other than CO_2 externalities that inhibit the adoption of energy efficiency and carbon saving technologies.
- Improving the dynamic efficiency of the ETS by overcoming market failures in the area of technology innovation and diffusion.
- Delivering social objectives other than carbon efficiency, such as the promotion of energy security or social equity, or the mitigation of local pollution.

- Ensuring that abatement within the ETS sectors proceeds in a manner that supports cost-effective carbon abatement in non-ETS sectors.
- Addressing deficiencies of the ETS design such as mitigating the risks of allowance price uncertainty for long-term investments in carbon reducing innovations.

However, the fact that positive combinations between an ETS and other instruments are theoretically and practically possible does not mean that, by definition, such combinations will result in a better social optimum when an ETS is introduced into an existing policy mix or when a new, additional instrument is implemented next to an ETS. This may be due to all kinds of 'policy failures', including a poor mix of policy instruments resulting in conflicting or negative interaction effects. Hence, the design of an optimal policy mix is a matter of careful fine-tuning of mutually consistent instruments, which each instrument addressing a specific objective or market failure.

Moreover, as noted above, when an ETS is in place and the cap is set over a certain period, aggregate emission reductions will be set solely by the ETS cap. Instruments which target emissions covered by the ETS cap will contribute nothing further to emission reductions - unless they are sufficiently stringent that they make the ETS redundant, resulting in a carbon allowance price equal to zero. This means that, once the cap is set over a certain period, the justification for maintaining or introducing such instruments must rely upon one of the rationales mentioned above, rather than on the contribution of the instrument to overall emission reductions.

A specific example: policy instruments besides the EU ETS to stimulate CCS
In order to meet the ambitious *Roadmap 2050* target for the ETS sectors, long-term and large-scale investments are needed in carbon saving innovations such as CCS. At present, however, such investments are faced by a variety of constraints, including:
- The EUA price is uncertain and, at present, relatively low, mainly due to the economic crisis. For the coming years, the EUA price is expected to stay relatively low and may increase only slowly up to 2020. At the same time the costs of CCS are relatively high compared to the current and expected EUA prices up to the 2020s and beyond. Over the coming decades, up to 2050, however, these costs are likely to decrease due to technological learning.
- CCS is still in its demonstration phase, involving a first-mover risk for companies pursuing CCS operations. This adds to the lack of economic viability and certainty on return of investment.
- In addition, CCS has other barriers, such as a lack of social acceptance, the need for investments in and access to 'public goods' such as CCS transport infrastructure, or the lack of clear specifications of CCS property rights, in particular who is responsible for the transport or storage of carbon, including carbon leakages.

So, even if the EUA price would rise to substantial levels over the coming decade, it is unlikely that investments in most types of CCS would take place. This has raised the question which type or combination of instruments, in addition to the EU ETS, may best address the constraints in general and the lack of economic viability/certainty in particular. Notably for the latter constraint, two categories of policy instruments have been suggested: regulation and financial or market-based instruments to stimulate investments in CCS. These options in these categories are considered below.

The interaction of the EU ETS and carbon regulation
In order to stimulate investments in CCS, regulation besides the EU ETS, in particular the introduction of an 'emissions performance standard' (EPS) or a 'CCS mandate' for specific types of individual installations has been proposed. The major advantage of regulation is that it has the guaranteed effects that some types of (new) plants - particularly unabated coal-fired power plants - will not be built. On the other hand, however, carbon regulation in general and an EPS

in particular have some drawbacks, notably when interacting with a cap-and-trade system such as the EU ETS. These drawbacks need to be considered in coherence with the advantages:

- In principle, carbon regulation next to the EU ETS does not improve the environmental effectiveness of the scheme, as total ETS emissions are set by the cap. If all assumptions with regard to the carbon market are valid, regulation would increase social costs. However, if the 'boom and bust' cycle of investments would occur and intrinsic uncertainties are perceived large, this is less certain; carbon regulation might decrease social costs.
- Whereas an ETS sets an overall emissions cap and provides companies and the covered installations the freedom and flexibility to meet this cap in a cost-effective way, carbon regulation reduces this flexibility and restricts or prescribes the type of technology to be used at the individual plant level. This argument is not valid if the option that is prescribed would have been implemented anyway: in that case the regulation diminishes uncertainty and market prospects for alternatives may be improved.
- If carbon regulation is binding and the ETS cap is fixed, it reduces the demand for emission allowances and, hence, lowers the price for these allowances, thereby reducing the incentive for carbon abatement by all other installations not covered by the regulation. This adverse carbon price effect can be nullified, if allowed, by lowering the cap.
- The effectiveness of regulation for stimulating CCS is unclear. If CCS is still technologically risky or not yet proven at a large scale, not economically viable or still very expensive, and/or has social acceptability problems, companies may decide to not invest in new power capacity at all or may move investments to Member States without regulation (see for the case of regulation in the Netherlands (Groenenberg et al., 2010)). Each specific situation will require further study on how regulation would work out, or be implemented on an EU level. Rather than encouraging investments in CCS, regulation may stimulate investments in other (unintended) carbon saving technologies such as renewables, a switch from coal to gas or to co-firing with biomass and, in particular, nuclear power generation, as nuclear will likely benefit most from the regulation-induced increase in base load power prices to industrial end-users.
- One could argue that a case can be made for a regulatory incentive for a timely retirement of older high carbon assets. Old, inefficient coal-fired power plants cannot be part of a zero emissions fuel mix and measures to force timely retirement of these assets could be regulated.[18] The cost of doing this at the right time will be low compared with emissions trading only - as many of them would have been retired anyhow. A clear signal to laggards that continuing carbon intensive power production is not an option from a certain moment in time adds to the certainty that the zero carbon electricity system will be realised. Timely announcement of this type of regulation is important to avoid legal battles, to not hamper security of supply and to stimulate the business case for clear investments.
- The arguments above are valid both for consideration of regulation at the EU level and in individual Member States. Several Member States are considering regulation with regard to coal-fired power plants (e.g., the United Kingdom, Ireland, the Netherlands). This has raised the issue whether existing EU regulation allows the setting of a stringent, binding carbon EPS, besides the EU ETS. The EU Treaty leaves room for national measures on top of EU policies that would be required to protect the environment. On the other hand the current IPPC Directive states that "the permit shall not include an emission limit value for direct emissions of that (greenhouse) gas unless it is necessary to ensure that no significant local pollution is caused". A proposal by the European Commission for a Directive on industrial emissions contains similar language. However, at the same time the Directive for Geological Storage of CO_2 explicitly opens a perspective on an EU wide regulation for CCS by 2015. When the Directive on CCS was passed, it included several amendments of other Directives (such as Water, Waste, IPPC) to enable CCS. In all, the legal situation still has some uncer-

[18] The ECF Volume 1 analysis assumes that existing plants should be able to produce to the end of their assumed lifetimes, at which point their retirements will create the market demand required for investments in low carbon technologies. ECN does not propose to force early retirements, but to consider diminishing uncertainty for investors.

tainties. It could be argued that a case for a stricter national approach can be made, but careful legal analysis will be needed and possibly an amendment of the IPPC Directive may have to be passed along with an EU-wide Directive for regulation. Resolving legal disputes may take years.

The arguments outlined above refer in particular to regulation besides the EU ETS, but most of them also apply to the coexistence of a CCS mandate and a cap-and-trade system. A major exception is that, compared to an EPS, a CCS mandate can be more easily stipulated and implemented for a large variety of different installations. In theory, a mandate is most likely more effective in actually implementing more investments in CCS, although it also hardly addresses the issue of low/uncertain carbon prices on CCS investments. One of the main objections to a CCS mandate, even at a date in the future, is that CCS is not yet a proven and accepted technology at a large scale and, therefore, from a policy point of view, it may be hard to already introduce a mandate until CCS is indeed a proven and accepted technology at a large scale. On the other hand, the power sector has been really pushing for CCS. CCS as a whole is not in the demonstration phase; in many cases, it combines existing technologies and practices, just changes the context. But, if not designed cautiously, it might lead to legal procedures by those that will be affected by such regulation.

The interaction of the EU ETS and financial instruments

There is a large variety of other, so-called financial or market-based instruments that, in coexistence with the EU ETS, stimulate long-term investments in carbon saving innovations, such as CCS or renewables at large scale, by addressing the issue of relatively low/uncertain EUA prices. These instruments include a feed-in or subsidy system, a certificate system, a tender system, or a system of long-term carbon pricing contracts.[19]

A basic characteristic of financial instruments is that they encourage investments in carbon saving innovations by reducing the economic constraints or risks of such investments by either (i) offering a fixed or flexible subsidy next to the (power) market output price, e.g. through a feed-in tariff/subsidy or a certificate system, (ii) offering a subsidy either to capacity installed or output of carbon free production, or to either a tonne of CO_2 or a specified target volume of CCS over a certain period (tender system), or (iii) guaranteeing a fixed, long-term carbon price that may be set at a relatively high level (carbon price contracts).

The impact of these financial instruments on the economics of long-term investments in carbon saving technologies consists of one or both of the following effects:

- It enhances the competitiveness or profitability of investments in CCS by providing a subsidy to the output of this carbon-saving technology. CCS is still a new technology showing positive externalities in terms of technological learning that may reduce costs significantly over time if CCS installed capacity increases substantially. Therefore, a temporary subsidy can be justified to realise and account for this expected decline in CCS costs due to technological learning.
- It reduces the risks of long-term investments in carbon saving technologies by reducing the carbon price uncertainty - or, better, by shifting this uncertainty from the private investor to the public sector - either by offering long-term certainty on carbon prices (i.e. contracts) or through a mechanism that compensates more or less automatically for (unexpected) low levels or fluctuations of carbon prices (i.e. certificates, feed-in tariffs).

[19] For a discussion of different options of long-term carbon pricing contracts, see Helm and Hepburn (2005), Kemp and Swierzbinski (2007), and Ismer and Neuhoff (2009). The other financial instruments mentioned (feed-ins, certificates, tenders) have already been applied widely across EU Member States in order to stimulate investments in renewables or energy efficiency. For some recent analyses and evaluations of these instruments see, among others, De Jonghe et al. (2009), Verbruggen and Lauber (2010), Bertoldi et al. (2010), and Couture and Gagnon (2010). For an analysis of the interactions of the EU ETS with green and white certificates, see NERA (2005).

Each financial instrument has its specific sub-options, each with its specific features, advantages and disadvantages, either as an individual, stand-alone instrument or in coexistence with a cap-and-trade system such as the EU ETS.[20] As a group or category of instruments, however, when interacting with a cap-and-trade system they have some objections similar to the coexistence of the EU ETS and carbon regulation. In addition, the design or implementation of financial instruments may show some higher administrative or transaction costs than regulation. On the other hand, in order to stimulate long-term investments in carbon saving innovations such as CCS, the interaction of the EU ETS with financial instruments, compared to carbon regulation, offers some advantages. The considerations for interaction of financial instruments with the ETS to stimulate CCS include:

- Financial instruments can be designed to cover a broader range of energy and industrial installations across the EU ETS, e.g. through a tender system offering either a subsidy to meet a specified target volume of CCS (with the subsidy per tonne CCS resulting from the tender system) or a subsidy per tonne of CCS (With the target volume of CCS resulting from the tender system), regardless the type of energy/industrial installations covered by the scheme. As a result, financial instruments can benefit from higher market liquidity due to a broader range of participants, more flexibility and, hence, a higher efficiency to meet a certain CCS target.
- Financial instruments offer more flexibility regarding the question ‘who is going to pay for these costs?’. In the case of regulation, CCS costs are initially paid by the producers (polluters) who will try to pass on these costs either fully or partially to their end-users, i.e. firms and/or households, thereby affecting the producer/consumer surpluses of these producers, firms and/or households. In the case of financial instruments, however, a (major) part of the CCS costs, i.e. the subsidy involved, is initially paid by the public sector that can decide whether these costs are passed on either to certain taxpayers (firms and/or households) or, due to budgetary or fiscal constraints, to certain end-users (firms and/or households) by charging a specific levy on end-users products to cover the costs of these subsidies. If this is done, it might negatively affect the political feasibility of the financial instruments, as the scheme might be seen as ‘subsidising fossil industry’ and replacing socially more acceptable investments such as hospital beds.
- The pass-through of CCS costs to electricity prices that accrue to power producers may be less due to the subsidy involved and, hence, that less ‘windfall profits’ accrue to alternative carbon saving technologies such as nuclear power generation.
- Financial instruments are more compatible with the basic philosophy or premises of the EU ETS.

Overall, financial instruments tend to be more cost-effective in reaching a certain CCS target than regulation because they (i) address the economic constraints of CCS investments, i.e. low/uncertain carbon prices, more directly, (ii) offer higher market liquidity and flexibility, (iii) may reduce ‘unintended’ side-effects such as stimulating nuclear power generation or co-firing of coal and biomass, and (iv) may reduce the risk of losing sectoral competitiveness to foreign countries. A related advantage of the latter effect is that financial instruments to stimulate CCS can be implemented at the level of individual Member States without the legal uncertainty mentioned above, although they will certainly have to be approved by the Commission services. A drawback is that financial incentives will not offer any certainty of implementation: a producer may assess whether to accept subsidies or not, he cannot be obliged to do it.

To conclude, both regulation and financial incentives have advantages and disadvantages. Here, they are roughly summarised as follows.

[20] For a discussion of these sub-options, features, advantages and disadvantages, see the references mentioned in the previous footnote.

Table 2.1 *Preliminary assessment of additional policy instruments*

	Regulation	Financial incentives
Reduces uncertainty in the market	0/+	0/+
Address the economic constraints of CCS investments	-	+
Improves learning of new technologies	0	+
Supports retirement of old plants	+	-
Business acceptability/risk of legal procedures	-	+
Pressure on government budget	+	-
NGO acceptability	+	-

Reducing uncertainty in the market ranks equal: regulation will apply to everybody, but may have unintended consequences. Financial incentives are more focussed, but actual use is voluntary. Learning of new technologies can easier be directed by financial instruments than by regulation. On the other hand, retirement of old plants is easier to force - it is hard to defend spending public money on retiring strong polluters. This is the reason a policy package could be considered that combines the potential advantages of both types of instruments.

A policy package is probably needed to facilitate CCS for new fossil fuel generation, even after the current phase of demonstration projects (compare Chapter 3). To bridge the time between availability of CCS, such a package could guarantee that new fossil fuels plants built from a certain date are capture, transport and storage ready - coal-fired power plants soon and gas-fired power plants somewhat later. As long as CO_2 prices remain low, CCS will not materialise without financial compensation or a clear legal signal. The difference between costs and CCS and unabated fossil fuel plants will differ from place to place and country to country and the CO_2 transport and infrastructure still needs to be developed. Temporary financial instruments comparable with the existing stimulation of renewable energy are probably best suited to cover the first stages of deployment of CCS as a follow up of the current demonstration activities. An ECN study has indicated that the costs of this type of financial support could be relatively small (Groenenberg, 2010). Over time a combination with regulation is an option. The potential advantage of a combination of carbon regulation and financial incentives is that it would ensure that all investors have to apply to the rules (which is not necessarily the case if only a financial instrument is used). In the current financial situation of European governments it cannot be imagined that a financial incentive would be applied for a longer time than strictly necessary. This could be part of the financial contract between a coal-plant generator and the respective government, but additional regulation could underline the temporariness. It could be announced in a timely way how and to which extent the regulation would replace the financial incentive. As unabated coal-fired power plants certainly will be unacceptable in a zero carbon power system, over time specific regulation to finish unabated coal could be considered.

EU member states could take the lead by introducing additional policy measures, e.g. to incentivise CCS as has been done in the United Kingdom and is being considered in Ireland and the Netherlands. Eventually, the same could be considered for gas-fired plants. As has been argued before, this package will not have any immediate environmental benefit if it does not coincide with a tightening of the emissions cap of EU ETS. Hence, ECN's strong plea to intensify the annual reduction.

A policy package of regulation and financial incentives might improve the investment climate for clean technologies by reducing uncertainty. It probably could diminish 'wait and see' behaviour of investors and contribute to a virtuous circle. It could show that the pathways of *Roadmap 2050* are indeed feasible. It could deliver empirical arguments that further reductions of the emissions cap after the one suggested in this report could be considered.

To conclude, in order to reduce uncertainty and further contribute to the internal market and European security of supply, additional policy measures next to strengthening of ETS need to be considered and must be designed with great care.

3. Strong additional technology policies needed

3.1 Introduction

Key to the energy transition that is needed to attain a zero carbon power system by 2050 is massive deployment of new technologies. The 2050 power system will be completely different from the current one. What it will look like is yet unknown, but some of the following basic elements will be included (Jones and Glachant, 2010):

- Electricity has a larger share of overall energy consumption, as it is an important part of decarbonising heating in buildings and offices, and of decarbonising the passenger transport system (Volume 1, see also PBL 2009). This larger share is compensated to a great extent by higher efficiency of its use. Therefore the overall production of electricity increases slightly.
- Many new clean technology options are developing. The essence of new technology is to learn and to invest. Learning is a combination of developing and sharing the relevant information and knowledge, implementing this in a gradual way in order to exchange insights from new knowledge and actual deployment, enabled by an effective policy framework. The investments will create the new capital stock that is needed to produce.
- The share of renewable energy has increased considerably, but how this will continue depends on non-economic barriers and relative costs, which at first is related to the success of deployment policies, but at a certain share in the global fuel mix, the technology costs do become more important. Unit costs will need to fall sufficiently so that any remaining subsidies are small. The real challenge at this stage moves to planning infrastructure and land use (Kramer 2009).
- In addition, the two other non-carbon options nuclear and CCS will play a role. The IEA (2008) has demonstrated that a (global) 450 ppm GHG concentration cannot be reached without CCS. Tavoni and Van der Zwaan (2009) indicate that even in the situation of a favourable development of CCS, large investments in nuclear energy are required to attain the 450 ppm concentration. Other studies are less certain about this, but indicate higher costs of reduction of global emissions without nuclear (IEA, 2008). Therefore, nuclear energy is a part of the European Strategic Energy Technology (SET) approach.
- A different electricity infrastructure is needed, in which both local generation and demand reduction are possible. High voltage transmission grids connect the regions with a concentration of renewable energy production (solar in the South, off-shore wind in the North Sea) with the regions in which consumption is concentrated and are needed for back-up and balancing.

In this chapter we will look at the technological changes that are needed to attain the zero emission goal and the policy instruments that have to support this ‘energy revolution’. Section 3.2 classifies the different clean technologies according to their stages of maturity and sketches the actual SET approach. Section 3.3 presents elements of technology roadmaps for key new technologies. Section 3.4 gives an overview of the policy instruments that are needed against a background of different policy goals and scenarios of feasibility. Sections 3.5-3.7 present some proposals that can be considered for renewable energy, CCS and nuclear energy.

3.2 Characterisation

The European Strategic Energy Technology Plan gives the following main characteristics of relevant clean energy technologies[21].

Table 3.1 *Main characteristics of clean energy technology groups*

	Group 1: close to market competitiveness	Group 2: emerging technologies on the verge of mass market penetration	Group 3: new technologies
Innovation status	Market for the technology exists with maturing supply chain Target is to improve performance and reduce costs through incremental innovation (market replication, supporting RD&D)	Up-and-coming technologies in emerging markets. They require enhanced innovation (based on large-scale demonstration), combined with further research	Technologies are driven by RD&D and require RD&D based innovation, pilots and eventually demonstration to reach market
Technological maturity	High. Incorporates limited risk and significant likelihood of success. High attractiveness to industry	Medium. The uncertainty regarding market success of RD&D limits the attractiveness to private investments	Low. The high risks and uncertainties associated with the technology and its market potential significantly limit private investments
Time horizon before return on investment	Short	Medium	Long
Main support scheme	Massive deployment incentives; medium RD&D	Targeted deployment incentives; relatively high RD&D	Deployment only in specific situations; relatively high RD&D
Upfront RD&D investment	Medium: further adaptation of existing technology and infrastructure	Relatively high: further RD&D and additional reinforcement of existing technology and infrastructure	Relatively high. Includes large RD&D and significant adaptation of technology and infrastructure
Composition	Most energy efficiency technologies; on-shore wind; solar heating; electricity transmission; nuclear	Offshore wind; solar PV; CSP; CCS; 2nd generation biomass; geothermal; smart electricity distribution	Nuclear fission (4th gen.); hydrogen and fuel cells; ocean energy

Source: adapted from European Commission, SET (2009).

ECF has investigated the capital costs, learning rates in a favourable global context, and key barriers to actual deployment of clean energy technologies, compared with conventional coal and gas-fired power generation.

21 Other classifications are comparable. See e.g. Grubb 2008. For an overview of all relevant technologies, see JRC (2009). The new technologies (group 3 of the Table) will not be dealt with in this chapter as it is not expected that they will take a large share in the fuel mix before 2050.

Table 3.2 *Key aspects of power technologies*

	CAPEX 2010 [€/kW]	Learning rate [%]	Key barriers
Onshore wind	1000-1300	5-	Spatial
Offshore wind	3000-3600	5-	Cost, transmission, offshore conditions
Solar PV	2400-2700	15	Cost, storage, intermittency
Solar CSP excl. storage	4000-6000	high	Location, cost, transmission
Biomass (dedicated)[22]	2300-2600	1.0*	Supply, sustainability
Geothermal	2700-3300	1.5*	Spatial, technology
CCS coal	2800-3000	8.0	Legal, public acceptance, costs
CCS gas	1900-2300	8.0	Legal, public acceptance, costs
Nuclear	2750 (France) to 3300 (other)	3 (France) to 5 (other)	Waste, public acceptance, flexibility
Conventional coal	1400-1600	0.5*	
Conventional gas	700-800	0.5*	

* Annually.
Source: ECF Volume 1.

Table 3.3 *Development of CAPEX of key technologies*

[€/kW]	2010	2030	2050
Onshore wind	1000-1300	900-1200	900-1200
Offshore wind	3000-3600	2000-2400	1900-2300
Solar PV	2400-2700	1000-1400	800-1200
Solar CSP excl. storage	4000-6000	2900-3500*	2200-2600*
Biomass	2300-2600	1600-1900	1300-1600
Geothermal	2700-3300	1700-2000	1500-1800**
CCS coal (new)	2600-3000	2000-2400	1800-2200
CCS gas (new)	1900-2300	1400-1800	1200-1600
Nuclear	2700-3300	2700-3300	2700-3200

* Rather uncertain due to emerging technologies.
** Enhanced geothermal still excluded.
Source: ECF Volume 1

Table 3.4 *Indices Estimated Cost of Electricity (gas-conventional=100)**

[€/MWh]	2020	2030
Coal conventional	70	60
Gas conventional	100	100
Coal CCS	-	100
Gas CCS	-	150
Nuclear	100	80
Wind onshore	80	60
Wind offshore	130	100
Solar PV	130	80
Solar CSP	190	140

* Excl. system costs, 60% renewable energy scenario, oil, gas and coal prices until 2030 adopted from IEA 2009g, CAPEX, OPEX and learning rates ECF analysis.
Source: ECF analysis.

It is clear from these tables that the outlook of especially solar PV is favourable. Onshore wind also has a good economic prospect, because it is the first renewable technology that will become

[22] In reality the combination of biomass, coal and CCS might also be extremely useful as eventually this may lead to *negative* CO_2 emissions.

cost competitive with fossil fuels. On the other hand, solar CSP will remain rather expensive but it has the possibility to store its energy, whereas wind and solar PV are intermittent. Coal and gas-fired CCS CAPEX will also decrease considerably, but these technologies will always remain more expensive than conventional coal and gas as it costs energy to capture, transport and store the CO_2.[23]

The SET Plan has proposed seven technology roadmaps for the most promising options and formulated concrete ambitions in 2020:
1. Wind energy has to attain up to 20% of EU electricity.
2. Up to 15% of electricity has to be produced by solar energy (12% PV and 3% CSP).
3. To accommodate items 1 and 2, the electricity grid has to be able to integrate up to 35% renewable energy in a seamless way and has to operate along the 'smart' principle; this is a first step to attain a fully decarbonised system by 2050.
4. Sustainable bio-energy must deliver 14% of the overall energy mix in 2020.
5. CCS must become cost-competitive with CO_2 prices in the period 2020-25.
6. Nuclear energy will continue to provide around 30% of European electricity. A generation IV prototype must be in operation by 2020, allowing commercial deployment by 2040.
7. 25-30 European cities will be in the forefront of the energy revolution.

In the ECF analysis these shares of specific renewable energy technologies are not reached in 2020, but that is not the essence of the SET approach. The essence is that Europe joins forces and that a way forward has been sketched that is sustainable from a technology and cost perspective. As long as participants agree upon concrete steps that have to be taken and on the ultimate target, the precise moment to attain a specific target for each specific technology is less important. These concrete steps, for which we consider a joint learning approach most relevant, will be elaborated; i.e. wind energy, solar PV and CCS. Nuclear will be dealt with only briefly as this option is already mature and competitive and mainly needs a clear policy framework in which the general topic of technology learning is relatively less relevant. Efficiency options are dealt with in Chapter 6. Bioenergy is not only relevant for the power sector, but may be used in other ways in the zero-carbon energy system as well. It is important to mention that until 2050 biofuels could be the only option available to decarbonise shipping and air transport and they therefore need priority; technology development of biofuels should search especially for bio-kerosine (see Chapter 7). On the other hand, wood-based bioenergy in power plants with CCS is the only option to make CCS really carbon neutral and even carbon negative. PBL (2009) rightly advises to take a strategic decision to make full use of the limited and uncertain potential of biomass. This could be done in the context of the Climate and Resources Directive that will be looked at in Chapter 8.

Formally, the SET plan includes basic and applied research, pilot projects, test facilities, demonstration (for full-scale viability) and market replication measures (from demonstration into first markets). But it does not actually include deployment activities - these are the responsibility of the EU member states. The interaction between SET activities and deployment could be improved considerably[24]. "Large-scale programmes for R&D may have more impact on the climate change problem than shorter-term targets for renewables and biofuels" (Helm, 2009). As RD&D is less expensive than deployment - a ratio of 1: 10 is often mentioned (IEA 2008) - the potential reward of effective RD&D in decreasing deployment costs could be huge (Sagar and van der Zwaan 2005). In other more explicit words, "It is essential for future research to address the important policy question of the optimum level of total spending and allocation of innovation funds between R&D and capacity deployment" (Jamash and Kohler, 2008). In line with many calls by analysts to reverse the trend of declining public energy R&D, it is understandable

[23] Compared with the recent IEA *World Energy Outlook* (IEA 2009g) estimates, ECF ranks onshore wind Cost of Electricity more favourably in 2020 and the cost decrease of solar PV is relatively fast. Estimates of CAPEX are more comparable.
[24] Interaction of policy instruments might even be more complicated. It has been suggested that effective emission caps could stimulate innovation activities in the private sector (Weber and Neuhoff 2009).

that the IEA Ministerial Conference formulated an aim to double public R&D investments in the period 2009-15 (IEA 2009f).

Unfortunately, the optimal division between RD&D and support to market deployment is still uncertain. After a thoughtful analysis of the issue, a recent study concludes that "the black box of technology learning has not yet been opened" (Junginger, 2008). They even found no indication that RD&D efforts could influence the slope of the learning curve of supply technologies: "No structural trend was identified that progress rates change over time neither with increasing market diffusion nor with changing R&D support". However, they did find indications that the slope of learning curves could be influenced by policy measures with respect to energy efficiency. In the few cases of solid empirical research on this issue, it was illustrated that especially a close interaction between public R&D, commitment by industry and deployment subsidies can be successful; in such an integrated approach the effectiveness of investments in R&D can be more than twice the effectiveness of deployment subsidies (a learning rate of 12.6% vs. 5.4% in the case of wind energy)(Klaassen et al, 2005). It was also indicated that RD&D could help in tackling a levelling off of the learning rate that might be possible when a specific technology matures. This might for example be important in the case of solar PV. Other analysis reaches comparable conclusions about the fact that R&D inputs influence the learning curve of emerging technologies (Jamash and Kohler, 2008). This is not only related to public R&D, but especially to incentives for private R&D that might have a useful interaction with deployment.

It is suggested that more precise roadmaps should be developed for all clean energy technologies that offer a joint vision for 2050 for the development and deployment of that technology. These public-private roadmaps have to include: a vision of milestones to be achieved by a specific date; critical RD&D and deployment activities to achieve these milestones; identification of which barriers have to be overcome and what policies are needed to do this; recommendation of how to share responsibilities among public and private partners. Progress made in member states can be shared in a so-called open method of coordination, aiming to benchmark national policies and sharing best practices (PBL 2009). In this way more interaction between deployment and RD&D could be attained. "Focusing on rapid upscaling of production is likely to divert focus from cost-efficiency, thereby delaying technological learning" (Neuhoff and Twomey, 2008). As mentioned earlier, such roadmaps already exist for the RD&D stage of technologies (SET plan), but up to now no overall attempt has been made to include the deployment phase and supporting policies. This could be done in close interaction with the International Energy Agency that is in the process of drafting global roadmaps as the deployment has to be global (IEA 2009a, b, d). For example, offshore wind will require subsidies of billions of euros before this technology will be competitive. A linked approach of additional RD&D as promoted in the SET plan, and deployment policies as implemented in the EU member states could reduce overall costs. A further development of technology roadmaps might give indicative targets for specific technologies in interaction between the European Commission and member states. This might be especially useful if based upon one common approach of which one or two of the ECF pathways could be an example. Without such integration, the roadmaps run the risk of being developed independently from each other. Of course, it is acknowledged that EU member states have the sovereignty of framework conditions in their country, but these countries are increasingly linked and one common non-binding but forward looking overall vision is extremely important to combine insights and share best practices. It would certainly help in sharing views on which incentives remain needed for how long.

3.3 Examples of elements of three roadmaps for key technologies

Below we will present some basic elements of roadmaps for those technologies that need both RD&D and deployment activities (group 2 of Table 3.1) and could attain a relatively large share in the fuel mix: wind energy, solar PV and CCS. CSP will not be dealt with specifically as this will probably remain a somewhat smaller option.

Box 3.1 *Elements of a roadmap on wind energy*

- Key barriers to accelerated introduction of onshore wind are spatial planning and interaction with inhabitants of the areas in which investments are made. Barriers to further deployment of offshore wind are again spatial planning, due to multi-purposes of the sea, costs, transmission and the need to improve technology to take offshore conditions into account (ECF workshop).
- Especially onshore wind is disputed strongly by inhabitants of densely populated countries and in areas close to nature reserves. This NIMBY problem was a main driver towards offshore developments. More cooperation is needed and looked at, e.g. by participative ownership of stakeholders. Higher capital needs and a tendency towards large wind parks make this difficult.
- Beside large hydro, onshore wind by now is the most competitive renewable electricity option and the 2020 European target will stimulate its deployment substantially. The SET plan envisages a 20% share of wind energy in total European power generation (onshore and offshore combined); in a climate policy scenario the IEA envisages 9% of global power by 2030 (IEA 2009g) and 12% by 2050 (IEA 2008). Wind energy is the largest renewable option in all ECF pathways, ranging from 11 to 30% in 2050. With such a capacity enlargement and a continuation of the current learning rates - i.e. 5% in the ECF analysis; the IEA mentions 7% for onshore and 9% for offshore - onshore wind might be competitive at good locations before 2020 (Junginger 2008). For offshore this will take considerably more time.
- 75% of onshore investment costs consist of turbines. By now costs have decreased by scaling up the turbine. Learning will be incremental and a further increase of turbine size will require affordable materials with higher strength to mass ratios before the turbines will become much more cost-effective. This will be the main driver to decrease investment costs.
- The cost share of foundations, maintenance and transmission are much higher in offshore wind. Greater reliability is a key issue. More ‘dedicated’ turbines are needed, e.g. with direct-drive generator and without a gearbox, which will diminish maintenance costs. New foundations are needed in deeper water. Investment costs will be further reduced by increasing preparatory work onshore. Offshore still needs considerable RD&D and increased coordination and sharing of information could lead to additional benefits (IEA 2009a)
- The deployment of wind energy is the most single pressing reason why governments, TSOs and regulators should accelerate the development of integrated, economically optimal plans for new transmission. With regard to offshore wind the North Sea grid will develop bottom up from the national approaches, but overall coordination in the framework of ENTSO-E and by the EU North Sea coordinator is extremely useful. A joint development of transmission and generation has to be pursued.
- Flexibility will become a key issue. Predictability of wind can be further improved. Market structures may be further improved, e.g. by intra-day bidding (see Box 5.1).
- The incentive systems for onshore wind are successful. They have to remain transparent, stable and predictable to enable infrastructure planning and investments. A decrease of the level of onshore support should be announced beforehand to encourage technology towards competitiveness. Such a maturity in stimulation has not yet been reached everywhere for offshore wind. Feed-in tariffs, green certificates and tender systems are in processes of further improvement. Joint policy learning is possible.
- This is especially relevant as the share of offshore in total wind energy deployment will increase globally from close to zero nowadays to possibly 19% in 2030 and 32% in 2050. In Europe this might be considerably higher due to a higher population density and superb opportunities in the North Sea region. Therefore ECF Volume 1 assumes a share of 50% for offshore wind in 2010.

Box 3.2 *Elements of a solar PV Roadmap*

- Key barriers to accelerated introduction of solar PV are high costs, intermittency and storage (grid integration) and spatial requirements.
- Ambitions for solar PV are set at 12% of European power in 2020 (SET Plan) and 11% of global electricity production by 2050 (IEA 2008). The latter share is considered to be rather low by some experts (Sinke, p.c.) ECF expects a European share in 2050 of solar PV of 12% in the 60% renewable energy pathway and 19% in the 80% renewable energy pathway. Up to 2020 the main increase will occur in the built environment, but subsequently investments by utilities will increase as well.
- Solar PV modules are produced in different ways. Currently, the largest share is taken up by wafer-based crystalline silicon (85-90% of the market), but thin film technologies are emerging (from 10-15% today to 15-25% in the short term). Multi-junction concentrator cells are capable of a much higher efficiency of converting the sunlight into power (up to 40% instead of 25% of the wafer-based technology) but are still in the advanced laboratory or pilot stage. Other concepts ('third generation') are emerging. All PV cost targets up to at least 2020-30 can be reached by ambitiously continuing development of proven and emerging technologies. Real breakthroughs are not necessary to attain the target, but steady deployment and RD&D is needed.
- Actual costs are not determined by the PV modules, but by price and performance of the systems. The wafer-based silicon industry has shown a learning rate of (slightly more than) 20% with each doubling of capacity. The system prices may follow this progress ratio, but the uncertainties are much larger. For the long-term a decrease of the learning rate for solar systems to 0.15 or 0.10 is quite possible (see also Ferioli and van der Zwaan, 2009).
- A 'grid parity' (costs of solar PV equal electricity prices for small consumers) may be reached in Southern Europe around 2015 (and earlier in countries with high power prices and around 2020 in countries with lower prices). In North European countries the irradiation (inflow of the sun) is half of that in the South, and therefore grid parity may be reached around 2020 in countries with the highest prices and in 2030 with relatively low consumer prices. The main driver of the cost reduction is a reduction of CAPEX. ECF anticipates half of current CAPEX in 2030 and one third by 2050. This is in line with expectations of the IEA; the European PV Technology Platform is slightly more bullish.
- Up to a share of 6%, grid integration is not expected to become a major issue. However, at 12% it will be. This is a reason why smart distribution grids are already urgently needed in the coming decade, as during that period most solar PV will be connected to the distribution grid (see Chapter 5).
- Deployment and RD&D policies have to be interlinked as both of them are needed: the main driver of the cost reduction will be capacity increase, but ways in which new insights from laboratories can help must be continuously explored. This is exactly what is happening in strong 'solar production and research regions' in Europe.
- Next to stable deployment incentive systems, integration in building codes and standards are promising ways to stimulate solar PV. Because of the relatively high costs it is not expected that these will have great impacts before 2020 (IEA 2009d) but from that moment onwards their impact will increase, potentially starting in Southern Europe.

Box 3.3 *Elements of a CCS Roadmap*

- The key barriers are the unproven feasibility of the CCS chain at scale; costs (which will remain higher than the alternative of conventional coal or gas-fired power plants); legal aspects (liability, transport), public acceptance and eventually storage capacity.
- CO_2 capture is available today, but the costs need to be lowered and the technology still needs to be demonstrated at a commercial scale. Expected costs of coal CCS in 2020 amount to 48 €/tCO2 (€ 35 capture, € 5 transport, € 8 storage) that could decrease to € 36 in 2050 (due to lower capture costs) (McKinsey, 2009). Costs in gas and industry are higher. The Rotterdam Climate Initiative has demonstrated how transport costs depend on volumes

to be transported and stored. Transport of low volumes might be much more expensive than of higher volumes. Storage depends more on the uncertainty of the cost estimates and distances and ranges between € 3 - € 7 in some cases or € 9 to € 33 in other ones (RCI, 2009).

- CCS will need huge investments. Based on the Zero Emission Platform proposals, ECF estimates overall investments up to € 230 billion.
- Three main technologies are available: pre-combustion, post-combustion and oxyfuel. Especially post-combustion capture technology, which separates CO_2 from gas mixtures, is commercially available. Alternative means of capturing technology, such as membrane separation, are at the R&D stage. The aim is to decrease the energy penalty (the energy lost in the capture process) to less than 8% in 2020/25 (IEA, 2009b). Integration of the CCS chain has to optimise to achieve overall capture rates of more than 85%. Pre-combustion technology has to be demonstrated in IGCC plants. Oxyfuel systems offer a capture alternative by combusting fossil fuels in recycled flue gas enriched with oxygen. Especially the efficiency of this process has to increase.
- The IEA (2009b) proposes the following concrete steps:
  1. By 2020: various demonstration activities: reduce the energy efficiency penalty, prove technologies at large power plant scale, reduce capital costs by 10-12%.
  2. By 2025: commercially available systems with more than 85% capture have to be available for all coal and gas pre- and post-combustion.
  3. By 2025-30: an overall efficiency of at least 45% (LHV) has to be available.
  4. By 2030: capital costs have to be reduced by an additional 10%.
- Transport will start with a point to point pipe, but ultimately a connected grid makes more sense. The IEA proposes that a region-wide picture has to be available by 2012 and that 1200-1600 km of transport lines must have been installed in Europe by 2020. In 2050 this may increase to 20,000 - 30,000 km. Investment costs in 2020 might be some € 1.8 billion in 2010-20 and € 70 billion in 2010-50 (including industry). ECF estimates € 90 billion in 2010-50.
- Theoretically, available storage in Europe amounts to some 120 - 940 Gton, viable capacity as estimated by the IEA is 94 Gton of which in the IEA BLUE climate scenario some 15.6 Gton will be stored in 2050. Compared with other regions, this is a relatively high share. In the 60% renewable energy pathway ECF estimates that 17 Gt has to be captured and stored, of which 60-70% due to the power sector. These estimates are close.
- The roll-out of CCS has to start with demonstration activities, which are partly paid by private investors and partly by public funds. Actually the first generation of small demos (pilots) has been installed by now or is being built, in the range up to 50MW. Budgets have been reserved for the second generation of demo's, to be ready by 2014: € 1.05 billion from the EU Economic Recovery Energy Programme for the support of 6 projects and the revenue from the auctioning of 300 million emission allowances of the EU ETS have been set aside for the support of CCS and renewable energy (probably offshore wind); the value of this is some € 3 - 4.5 billion and the Commission has made a proposal as to which investments may benefit from these funds. The UK has announced funding for up to 4 CCS projects, the first of which is to be selected via a competition. The Netherlands has allocated money for one large-scale demo. It has been advised, e.g. by the UK Climate Change Commission, to consider a third generation of demos (3.5 - 4 GW) that build upon the experience gained with the second generation by selecting designs that have been tested before.
- The key question is how and when certainty has to be given to investors for the steps to be taken after these demonstrations. No consensus exists on this issue. On the one hand it might be argued that a well-functioning ETS will ultimately result in CCS if needed. On the other hand, one could argue that although ETS is capable of realising gradual changes in investment no proof has been delivered up to now that it can incentivise radical changes. The UK Climate Commission advises to wait for additional information. "It is likely that there will be a period where CCS is deemed viable but where the carbon price is insufficiently high to cover the CCS cost penalty. Successor support mechanisms would be required". An early signal is needed in this vision that it will be introduced and it should be introduced no later than 2016. The UK government announced that it will decide by 2018.
- In a more general sense it seems sensible not to wait for perfect regulation. However, at this

moment only 3 countries (UK, Netherlands, Germany) are thought to be relatively advanced in their efforts to transpose the recent CCS Directive into national legislation (Newbery 2009). Existing laws may be amended for demonstration projects. Their effectiveness has to be judged and this experience should be used in creating comprehensive CCS regulation frameworks by 2020.

- Public support is extremely important. It is urgent because some storage locations are close to populated areas, and local communities can either speed-up or slow-down activities. In the long run one cannot imagine an option with such sensitive aspects without some kind of solid public support. Activities in this respect are relatively absent.

3.4 What do we aim at?

At this moment the EU has two binding targets: 20% GHG reduction and 20% renewable energy in 2020. From a viewpoint of carbon reduction per se it does not make sense to have these two separate targets: one, aiming at GHG reduction, would be sufficient. The reason a specific target for renewable energy has been formulated is that renewable energy needs considerable 'learning' before it can play a role in the carbon market (IEA, 2008a). This is a convincing argument, but it is valid for CCS as well.

Separate ambitions could be formulated for GHG reduction and learning activities. This argument is firmly supported in relevant literature (IEA, 2008; Herzog, 2009; Helm, 2009). Global targets cannot be met without renewable energy and CCS, which are options that are still relatively expensive but have opportunities to reduce costs. The importance of nuclear as an option is that (1) it is an existing technology and (2) it makes the overall carbon reduction portfolio considerably cheaper. The actual EU targets reflect this reasoning only partially, however, as it has a separate target for renewable energy but this does not include CCS.

In conclusion: a long-term GHG reduction target could include specific sub-targets - and therewith instruments - for technology learning, but these could include *all* relevant technologies. Without such an approach it is impossible to have a long-term view and only the cheapest options in the short-term will be chosen[25]. As nuclear energy is a commercially available technology, the technology learning instruments have to stimulate renewable energy and CCS.

The next section will start with an analysis of the actual approach to stimulate renewable energy and suggest next steps, and continue with the activities that are needed to engage with CCS in the same way. Nuclear energy will be dealt with only briefly.

3.5 Renewable energy

Cost and non-market barriers like administrative hurdles (planning delays, lack of co-ordination between different authorities), insufficient grid access or social acceptance impede fast commercialisation of renewable energy. EU member states have started to improve the situation considerably. They have accepted a 20% target, which will be implemented mainly in the power sector. They are in the process of drafting National Renewable Energy Action Plans, which will be submitted to the Commission before the end of July 2010. At this moment different incentive systems to stimulate renewable energy exist: feed-in tariffs and premiums (in different variants), quotas (with tradable green certificates) and tenders. The European approach is rather dispersed: each country has to attain its own target and - besides the possibility to invest in joint projects - trade is only possible if a national target has been achieved. Therefore not much trade is to be expected, which probably will increase overall costs, as comparative advantages cannot be fully reaped.

[25] Compare the strong plea of Jacobsen et al (2009): "We strongly advise against policy at the EU level which focuses on minimising short-term cost and ignores the innovation/industrialisation challenge".

Only with a continuation of policy will the share of renewable energy further increase after 2020. In the ECF baseline, the 2020 share has increased up to 32% of the power fuel mix but subsequently it stagnates and the 2050 share remains 34%. In order to further increase the share of renewable energy, not only substantial progress has to be made up to 2020, but the foundation for next steps - for example in infrastructure, regulation for back-up - has to be laid. In Chapter 4 EU member countries are advised to develop long-term visions on the fuel mix they prefer. Based upon these visions, it would make sense to create long-term commitments for the period after 2020 (Ecofys 2008) A long-term commitment will continue to decrease risks, both with respect to commitment and support schemes. In addition, a further increase of renewable electricity will further diversify the fuel mix.

In a situation in which 60 or 80% of the European electricity market would depend on renewable energy in different national systems, a common European power market would have ceased to exist. At first sight, it seems advisable to strongly argue in favour of one common European incentive system for the period after 2020. However, it is not clear whether this would be a wise approach at this moment:

- It is uncertain which system delivers most. In theory, one would expect that tenders or obligations with green certificates would lead to the lowest costs due to the competition between producers that would result. This has not been shown to be the case (Busgen and Durrschmidt, 2009). The risk premium of such systems appears to be high. As compared to supplier schemes with no particular attention to risk mitigation, the levelised cost of electricity can be reduced by 10 to 30% (Ecofys 2008).
- Independent analysis shows that in wind energy feed-in tariffs have delivered a greater share of the feasible potential in countries having used this system compared with quota systems (IEA, 2008b). All incentives combined need a financial support of M€ 32 annually for a 20 MW park in Germany (feed-in tariff), M€ 48 in the Netherlands (feed-in premium) and M€ 54 in the United Kingdom (obligation system) (Ecofys, 2008). With regard to biomass the jury is still out. Furthermore, countries are continuously evaluating their incentive systems and are learning from actual experience. As Ecofys (2008) remarks, “improved design of existing policy support schemes may be more effective […] than a switch to a different policy scheme”.
- More than anything, the market needs stability and certainty. It would be unwise to announce the possibility of a new European approach only one year after the actual Directive has become valid.
- It is possible that some kind of convergence might emerge in a ‘bottom-up’ way. The UK has introduced ‘banding’ in its quota system in which e.g. offshore wind is rewarded more than onshore and it has introduced a feed-in tariff for solar PV next to the general green certificates. Portugal has successfully started combining a tendering for wind energy with the general feed-in system. Spain actually changed its feed-in tariff system into a premium system in which market elements play a greater role. The IEA expects that ‘hybrid’ systems will emerge (IEA, 2008b). Of course, a quota system benefits from more liquidity and a larger market. Therefore, countries with quota systems have a stronger interest in a combination of national systems than individual countries with feed-in systems.
- It is to be expected that the cost reduction because of learning is successful enough to end the additional incentives for options like onshore wind before the European power market becomes really distorted. A useful way to stimulate this is to announce on time how the incentives will be decreased in the future compared with today, in order to enforce improvements[26]. With feed-in tariffs and premiums this is easier to implement than in the case of green certificates. It is not yet clear what a situation of ‘fading out’ of incentives could look like and how this must be organised.

[26] This is the trend, cyclical fluctuations due to specific shortages in materials or capacity may occur.

Box 3.4 *Why do expectations of cost of renewable energy differ so much?*

Strangely enough, no precise estimates of the overall costs of renewable energy in Europe are available. This leads to a wide divergence of expectations in different countries, which does not help an overall approach and tends to make governments and investors hesitant. The examples of the United Kingdom, Germany and the Netherlands have been superficially compared. A system analysis of costs of renewable energy in the UK estimates (computed in euros) € 5.5 billion as additional cost of generation in 2020 (excl. intermittency and transmission), which is equal to 3.5 ct/kWh in 2020[27] (Green, 2009). In Germany the government expects an increase of the 'Subsidy' (feed-in tariff Minus average cost of generation) from € 3.3 billion in 2006 (for 51.5 TWh renewable electricity), € 4.5 billion in 2008 (72 TWh) to € 6.2 billion in 2015 (130 TWh) (Busgen and Durrschmidt 2009). This implies an average 'subsidy' per kWh decreasing from 6 ct/kWh in 2006 to 5 ct/kWh in 2015 and a further, steeper decrease up to 2020 in the order of 3 ct/kWh. German authorities expect a decline in the total subsidy for new generation after 2015. The Netherlands spent € 670 million In 2006 and expects to invest € 1.6 billion in 2015 and € 3.4 billion (for a possible RE generation of 55 TWh) in 2020. This equals an average of 8 ct kWh in 2006 and 6 ct/kWh in 2020. Therefore, large differences exist in the average level of support and the moment that a decline in overall support is possible. A joint analysis of this question is needed to generate solid and useful figures[28].

It would be useful to get a view on when the cost of electricity of renewable electricity equals fossil alternatives including a CO_2 price. If this will happen, no further technology specific incentive is needed anymore. This question is not only of budgetary importance but also has strategic policy relevance as it sheds some light on the merits of the different policy instruments. Some rough calculations have been made.

The relative costs partly depend on the CO_2 price. In case of an improved ETS system as sketched in Chapter 2, one may assume a CO_2 price of € 35 in 2020 increasing to € 80 in 2030 (IEA, 2009g). Without an improvement of the ETS system, most studies assume a 2020 price of € 20. A price of € 35 adds something like € 25 per MWh to the price of coal-fired power generation and € 12 to the cost of gas-fired generation; with the low CO_2 price the addition is € 15 respectively € 7. According to the ECF analysis, which largely depends on a global massive deployment of clean energy technologies, new onshore wind energy is competitive and nuclear energy is the cheapest base-load option in 2020 (see Table 3.4). This is in line with the IEA *World Energy Outlook 2009* (IEA 2009g) that by 2020 nuclear energy is the cheapest base-load option and onshore wind overtakes gas as the second-cheapest option if a carbon penalty of at least $ 50 is assumed. In 2030 all renewable energy investments, except CSP, are competitive with both conventional coal- and gas-fired power[29]. This enables a rough estimate of how the incentive systems of renewable energy power could develop and how they could influence the power market. In 2020 some 11% of the new power generation investments is stimulated by some kind of specific RE system (3% offshore wind, 6% biomass and 1% solar PV and geothermal each in the 60% and 80% RE pathways).

[27] Intermittency and transmission costs are also uncertain. The UK estimate adds 60% to the direct 'subsidy'; the German estimate is much lower: 15%.

[28] General modelling studies exist, but they do not reflect the different positions and expectations of member states. Furthermore, the short term electricity price increase does not have to be equal to the levy imposed or to the certificate price, due to the merit order effect. As especially wind energy has a higher place in the merit order, if renewable energy is added to an electricity market that already has adequate supplies of generation, one should expect prices to fall (Green, 2009). In the short run, the decrease of the price because of this merit order effect could be more or less the same as the uplift due to the levy or certificate price. In that case consumers don't have to pay anything. This is because the producer surplus has decreased. In the long run this could lead to a decrease of investments.

[29] This does not mean that new renewable energy does not generate additional costs at that time, as intermittency and flexibility costs still exist. Depending on assumed fuel and other costs and CO_2 prices, in 2030, coal-fired CCS (both new and retrofit) could be competitive vis-à-vis conventional coal, but gas-fired CCS is still more expensive compared with conventional gas.

According to the rough estimates above, in a low-carbon scenario in a favourable global context, almost no technology-specific incentives are needed anymore by 2030[30]. Combined with the development of more hybrid incentive systems, a tentative conclusion is that a case can be made that incentives for renewable energy will not significantly disturb the power market if global deployment of renewable energy is sufficient.

A final issue that needs to be discussed is the possible inclusion of neighbouring countries in the EU approach. This is especially relevant for CSP in North Africa and biomass in the Ukraine. It is expected that, even including interconnections costs, these countries offer cheap potentials. However, North Africa will increase supply to its own demand first - in the Ukraine the situation is different due to a lower increase of demand. Security of supply issues are at stake too. If these can be solved, together with an equation of their national demand, it seems useful to consider a joint approach in which (a) the neighbouring countries commit themselves to a certain additional supply of specific renewable energy in a long-term framework guaranteeing security of supply; (b) this would open the possibility for the EU to build interconnection, offer facilities and receive the clean power. In the case of CSP this probably will not take place before 2020 at a large scale, but with regard to biomass in the Ukraine it is worthwhile to explore the issue earlier.

A post-2020 situation in which the share of renewable energy will be further increased has to be prepared. Smart grids and preparation of how to deal with intermittency issues are needed regardless of whether 60 or 80% renewable energy will be reached. Visions on the long-term fuel mix - including a timely consideration on how to continue the incentive system - will enable governments to develop a post-2020 view on renewable energy. Although the impact of the increasing share of renewable energy on the functioning of the European market has to be observed attentively, a rough analysis has indicated that - given the assumptions of Volume 1 - the disturbance to be expected might not be significant as on average the European share of electricity that will be incentivised in a technology specific way might not exceed an order of 11 - 13%. The cost of changing the current incentives by now seems to be higher than the benefit. It would be useful to investigate before 2015:

- Whether the discussion about which incentive systems deliver most has led to firm conclusions.
- How cost differentials between renewable energy and fossil fuels have developed and whether a phasing out of subsidies for esp. new onshore wind projects is within sight.
- How regional markets have developed also in this respect.

3.6 Carbon capture and storage (CCS)

The IEA (2008) concluded that at a global level a 50% carbon reduction in the energy system is not possible without CCS. Most energy experts accept this conclusion and extensive modelling has also confirmed it (Stockholm Environment Institute 2009, Herzog 2009). ECF assumes that all carbon generation connected to the grid after 2020 will be equipped with CCS and all coal-fired plants built in 2010-20 will be retrofitted. This is in line with other studies. Their modelling results show that a low-carbon energy system can only be achieved in 2050 if no fossil power plants without CCS would be built after 2025 (PBL 2009). In this section the incentive system that is needed to install CCS will be discussed, building upon the analysis in Chapter 2. As shown in the *Elements of a CCS Roadmap* before, this is only part of the story. Other reports have dealt extensively with other important issues like the need to invest in CCS infrastructure, whether enough storage capacity is available and how to win public support (IEA 2008d).

[30] In a more pessimistic variant one could assume that offshore wind and solar PV still need specific incentives by 2030, e.g. because intermittency and other system costs have to be taken into account. In that case 13% of the power market in the 80% RE pathway and 11% in the 60% RE pathway still would need a technology specific incentive. In all cases subsidies will continue for investments of the past for periods up to 15-20 years.

What is lacking is a clear vision of the long-term approach and instruments that solidly foster progress. What will happen after the 2015 demonstration plants have been installed? It is almost certain that the CO_2 price at that time will not be high enough to bridge the cost gap between conventional coal (and gas) and fossil fuel plus CCS. There is a risk that no timely follow-up will emerge of the actual 12 demonstration plants that will be built and that a next round of demos would not even emerge. One might argue - and this has been done in Chapter 2 - that a strengthened ETS will *guarantee* the attainment of the CO_2 reduction that is needed. It is not necessary to introduce 'two guarantees' by means of both regulation and emissions trading in the final situation. But unpriced CO_2 is not the only market failure. Network effects, lack of information, transaction costs; all kinds of other aspects have to be taken into account. It is uncertain at which moment the CO_2 price will be high enough to make CCS rewarding and whether the price is stable enough to make huge investments a sensible thing to do. It is also a timing issue. Without more demonstration and deployment, costs will not decrease. But without the certainty that CCS is inevitable eventually, power generators (and industry) will hesitate to invest on a large scale. How can the cost gap of CCS be bridged?

It has been argued in this chapter that to some extent the position of CCS in the fuel mix is comparable with that of renewable energy: it is an essential option in the zero carbon fuel mix, it is on a learning curve and a temporary cost differential has to be bridged to make it competitive in a power market, including gradually increasing CO_2 prices. It probably has a more vulnerable position than renewable energy as "it may be difficult to impose stringent CO_2 control requirements until the viability of CCS has been proven" (IEA 2008d). Assuming the cost estimates of the ECF analysis are correct - and a recent ECN study does not present a different view (Groenenberg et al, 2010) - and the CO_2 price that may be expected in the strengthened ETS is included, coal with CCS could become competitive with conventional coal before 2030 (even if some CO_2 emission remains as the CCS does not capture 100%). Gas CCS, however, is still not commercially compatible with conventional gas-fired plants and possibly will not be in the 2030s. Therefore, the situation of coal CCS is more or less comparable with renewable energy: a temporary stage of 15-20 years has to be bridged in which the relative costs are too high; uncertainty is larger however, both with regard to large-scale viability and costs. It is suggested, in line with Chapter 2, to continue the current approach of maximal joint learning-by-demonstration investments, which will gradually scale-up. Demonstrations could be funded by a levy on the energy price or the revenue of the auction of emissions allowances. Comparable with renewable energy, member states could make their own choices in how to stimulate the demonstration investments and the first step of commercial deployment, and the Commission might overview or influence the process by its own financial means. Tender systems are used widely to induce industry to propose and realise specific objectives as defined by a national government or other public authority. In the context of CCS they may be used equally for the realisation of CO_2 capture installations, CO_2 pipeline trajectories or CO_2 storage locations - as all of them are needed. The European Commission already launched a call for tender to select CO_2 demonstrations. Feed-in tariffs could be used but are less preferable in situations in which the costs of the projects are uncertain or differ considerably, as it will be difficult to determine the tariff. The same is the case with a feed-in premium. A contract for difference stipulates that one party (e.g. a government) will pay the other (e.g. a generator) the difference between a pre-set level for the CO_2 price, equal to a level needed to make up for the costs of CCS technology and the CO_2 price that will be realised. A contract for difference may thus be used to overcome the uncertainty in the value of emission allowance units when CO_2 prices are still low and volatile.

As the coal-fired power generators know in advance how the ETS cap will decrease, they have no alternative than to switch to CCS at a certain moment, which in the ECF pathways will be before 2030. The exact moment is less relevant. "(The introduction of CCS) is rather a continuous replacement process that would still allow for a step-by-step implementation of both retrofit and integrated CCS technologies after 2020" (Praetorius and Schumacher, 2009). The optimal approach depends on the allocation of incentives spent on RD&D versus deployment and next on the timing of CCS deployment. Many uncertainties exist with regard to viability, costs, transport and storage options. Additionally, even with a clear announcement of a next round of demonstrations, uncertainty for investors will remain. These uncertainties argue in favour of as much 'policy learning' as possible, in which member states define the policy packages they prefer, according to their different situations - e.g. are new coal-fired plants planned or not, which alternatives are feasible - and preferences. The Commission could oversee this process and learning experiences have to be shared.

The gas-fired CCS trajectory is less clear as the costs could be even higher than coal-fired CCS and the carbon price reward is lower. The main remedy at this moment is explicitly to not forget gas-fired CCS in the learning process and to take the need for this option in the CCS roadmap seriously.

Our conclusions with regard to policies to encourage CCS are:

- Continue to invest in next rounds of demonstration activities. Learning will not have ended by the actual round of demo activities in 2015. New, larger ones are needed in all links of the chain (capture, transport, storage) to further decrease costs. A policy package including financial incentives is probably needed. Funding would be possible by a small levy on generation or auction revenues of emissions allowances.
- Make sure that new coal-fired plants today and gas-fired plants by 2020 at latest are fully capture ready.
- Ensure adequate regulatory frameworks, first mainly for the demonstrations and next for the complete systems.
- Evaluate in 2015 whether enough progress has been made.
- The strengthened ETS eventually will make deployment of CCS by fossil-fuel plants inevitable: for coal-fired generation this could be before 2030, depending on the effects of learning, whereas for gas-fired CCS this is less certain[31].

3.7 Nuclear energy

At this moment nuclear plants have the largest share in European power production. It is uncertain whether this share will remain stable or will decline. In the last years several EU member states have started the construction of new plants (Finland, France, Slovakia), announced the construction of new ones (Bulgaria, UK, Sweden), decided or will decide on life-time extension of existing ones (The Netherlands, Belgium, Germany) or launched a new debate on nuclear energy (Italy). However, in the next decade many plants will phase out and therefore in all likelihood the share of nuclear will decrease. New nuclear plants show evolutionary improvements of existing designs.

Three policy issues are relevant for nuclear energy: the possibility of reactor accidents, the presence of radioactive waste and nuclear proliferation. The risk of accidents remains unequal to zero, but the likelihood of such events has reduced significantly over the past decades (Van der Zwaan, 2008). Current safety risks of the full energy chain of nuclear are less than of coal and gas-fired generation and even hydro energy, but public perception is different (Adamantiades and Kessides, 2009). Both through more advanced reactor designs and improved operation standards, the risk of serious accidents is likely to decrease in the future (ECN, Kernenergie 2008; Van der Zwaan and Tavioli, 2009). Main proliferation threats are the use of enrichment facilities and spent fuel reprocessing. Centrifuge enrichment technology has become prone to proliferation because of its compact size, low energy requirement and low costs. This is a serious issue,

[31] Some CCS from gas-fired installations will be included in the 12 demonstration plants sponsored by the European Commission. The eventual necessity to oblige gas-fired power stations to be capture-ready will be complicated as many gas-fired installations are small scale or operate for a small number of hours only. The obligation might be formulated for large installations only or for those who operate more than a certain number of hours yearly, but in that case 'leakage' to smaller ones could occur.

which has a more global meaning than an increased or decreased share of nuclear energy in Europe. Indeed, it is also related to the existence of enrichment facilities. A combination of technical measures and legal and institutional instruments in an international context could be the way forward (Adamantiades and Kessides, 2009). Useful suggestions have been made by e.g. Lubbers (2009). This will be difficult to implement, but having slightly more or slightly less nuclear power in Europe probably will not determine the effectiveness of anti-proliferation policies. The issue of high-level radioactive waste will not disappear. This will remain a problem given that radioactive waste and fissile materials have been produced abundantly since the start of the nuclear era. Technical solutions for the safe storage of spent fuel exist, but the European public remains by and large deeply sceptical about nuclear waste disposal. Only a small number of European countries have been able to select sites as permanent repositories in deep geological formations.

The government has an important and probably decisive role in formulating a policy framework for nuclear energy. This will influence siting issues, reduction of planning and construction time, reduction of uncertainty in general and probably a guarantee for those issues that cannot be expected to be solved by a private party. High upfront costs of investment make the issue of regulatory uncertainty crucial; as long as this is not crystal clear, no private investor will risk his money. There is no reason to stimulate nuclear energy with specific technology related incentives as it is a mature technology in the commercial stage. At the same time, costs are high, which is partly due to complicated regulation and uncertainty about the outcome of political processes. This is the reason why ECF has assumed that the costs of nuclear energy in France, with an extensive and long tradition of constructing standardised plants, are lower than in other EU countries. Giving scope for such an approach in other EU member states could decrease costs with 10-15%. To make this feasible, difficult decisions have to be taken. EU member states could:

- Consider long-term options for high radio-active waste, probably together with neighbouring countries that participate in the same regional market. Indeed, those countries that benefit from security of supply and lower prices of a coupling of national markets could look at a joint solution of the negative effects of the options delivering these benefits as well.
- Streamline planning and the regulatory process in order to stimulate standardisation.

3.8 Conclusions

This chapter outlined a policy approach to stimulate the technology revolution that is needed to implement far reaching greenhouse gas emissions reductions. The following parts could be considered.

1. An explicit combination of the greenhouse gas emissions reduction target, deployment and RD&D policies.
2. A fast implementation of the SET-plan, in which RD&D gets a substantial stimulus.
3. The formulation of roadmaps for relevant renewable energy technologies, the power grid, CCS and nuclear, as has been started in the SET process, but including deployment and all relevant policy instruments. In an interactive process this will result in a forward looking 2050 fuel mix and technology vision for the power sector that combines the different roadmaps and could be linked with the suggestion we make in the next chapters to develop regional long-term visions on the fuel mix and long-term regional infrastructure plans.
4. For renewable energy:
    - A preparation for a post-2020 situation in which the share of renewable energy has been further increased. Smart grids, preparation of how to deal with intermittency issues are needed regardless of whether 60 or 80% renewable energy will be reached. Grids could become the enabler of specific regional (neighbouring countries) approaches. Visions on the long-term fuel mix, including a timely consideration on how to continue the incentive system, and frameworks of infrastructure development will enable governments to develop a post-2020 view on renewable energy.

- No common European incentive system is needed by now as the start of a formal discussion on this topic could disrupt existing investment plans and create uncertainty in the market.
- Before 2015 the development of costs, recent experiences in incentive systems and their possible convergence need to be assessed in order to investigate whether time is ripe to make a step forward towards a more common approach.

As a result of a strong global effort of investment in renewable energy, the implication of the ECF Volume 1 is to expect that by 2030 almost no subsidies or green certificate stimuli for new investments would be necessary due to the decreased costs of most renewable energy technologies, a higher carbon price caused by a more stringent ETS cap and combinations of market and regulatory mechanisms that at a certain moment would effectively prohibit construction of new high-carbon plants.

5. Next to EU ETS additional temporary incentives could be considered for deployment of CCS, similar to renewable energy. All new coal-fired plants and eventually larger gas-fired plants have to be fully capture-ready to prevent lock-ins. Small-scale CCS demonstration plants are operating or being built now and large-scale demo investments are foreseen in 2014-16. Initial cost differences between capture, small volumes of transport and storage, and the emission price will remain to be too high for further autonomous deployment of CCS. Therefore additional demonstrations are needed and it is suggested to further invest in financial facilities, probably as a part of a broader policy package (see Chapter 2) The difference between costs of CCS and unabated fossil fuel plants will differ from place to place and country to country and the CO_2 transport and storage infrastructure still needs to be developed. Temporary financial instruments comparable with the existing stimulation of renewable energy could include the first stages of deployment of CCS as a follow up of the current demonstration activities Member states could choose different types of financial instruments if they wish, similar to renewable energy. These could be funded by a levy on the electricity price and/or the revenues of the ETS auction: the polluter pays. Tender systems might be a preferred route for providing temporary subsidies, as they stimulate competition and allow governments to have a say in operating conditions. Other options are feed-in tariffs or contracts for differences. The SET plan roadmap could overview this process to enable joint European learning. It is advised to consider around 2015 what has been learned and what is the best way forward.
6. Nuclear is a mature technology and no specific incentives are needed. To stimulate a cost-effective European approach, those countries that have opted for nuclear energy have to consider seeking solutions for end-storage of high-level waste, if possible in the context of a regional market. Streamlining of regulatory processes will enable all of them to benefit from standardisation. High upfront investment costs make the issue of regulatory uncertainty crucial. This issue has to be considered by governments as in the end nuclear energy will remain a public-private issue. Without a clear position in a government ‘vision’ on the fuel mix, investments will not be made.

4. Does a low carbon power system need a new market design? The role of capital intensive generation

4.1 Introduction

A low-carbon power system looks different from the actual one. It is dominated by capital-intensive generation with on average low variable OPEX and fuel costs. Therefore, marginal costs generally will be low and only in moments of high price spikes a real return on investment can be made. But it is questionable whether these temporary high prices are politically feasible. This is the reason why Grubb et al (2008) have coined this problem the ‘economic paradox’, which is especially serious when the social discount rate diverges from the private one. Both in literature and practice the issue which type of market creates the right incentive to invest has been looked at extensively and it will be investigated which lessons could be taken into account in the realisation of *Roadmap 2050*.

Europe has launched a new approach to the power market in the 1990s in which competition is a core issue. This has been relatively successful and the Third Energy Package, adopted in early 2009 after long discussions, has demonstrated willingness to go forward and set new steps. The fundamental issue of how to attain a capital intensive zero-carbon power system has not been addressed in that context, however. On the contrary, both competition and environmental pressures have led to a wave of new gas-fired generation, which is relatively cheap to build, environmental relatively benign and faces relatively easy permitting problems. It is well possible that the new challenge of capital-intensive generation asks for a completely new approach. One might even argue that some aspects of the wisdom of the 1990s and 2000s have to be revisited and a new market reform is needed.

The aim of this chapter is to frame these questions more precisely and investigate possible ways of improvement. Pros and cons of different approaches will be considered and suggestions proposed on how to go forward. While changes to the current market structure will be required, no specific policy instruments can be suggested yet.

Section 4.2 introduces the changes in the structure of generation costs, Sections 4.3 and 4.4 offer two different approaches to deal with them. Section 4.5 argues that a government vision is needed and Section 4.6 concludes the chapter.

4.2 Capital-intensive generation

In the current European power market in most cases gas-generated power delivers the ‘marginal’ generation, the generation that sets the peak price in a competitive market. With fuel costs of 45-50 EUR per MWh this price is relatively high. Capital costs of the gas-fired generation are relatively low and generators are able to earn their money. Base-load prices are mainly set by coal-fired power. The general situation is one of relatively high fuel costs determining marginal costs and therewith prices.

The *Roadmap 2050* situation will be completely different, which may be illustrated in two ways. First, the capital-intensity will be looked at and next the way prices are derived from marginal costs.

Table 4.1 illustrates the higher capital costs of zero-carbon generation.

Table 4.1 *Costs of electricity and shares of fixed and variable costs in different pathways (1)*

	Costs of Electricity	CAPEX	OPEX, of which fuel	other
Baseline	77	29	40	8
80% renewable energy (2)	83	50	22	11
60% renewable energy	85	49	25	11
40% renewable energy	85	43	31	11

(1) Average new built 2010-50, CoE in EUR/MWh, real terms, weighted average based on CoE in each ten-year time frame.
(2) Remaining part half nuclear, half CCS.
Source: ECF Team analysis.

The current situation with regard to fixed and variable costs is comparable with the Baseline: Some 1/3 of all costs are related to fixed investments as showed by CAPEX, and 2/3 of the costs depend on variable costs. If the price equals marginal costs, 2/3 of total costs have been met. The remaining part has to be met by peak prices. Especially in a zero-carbon future with a high share of renewable energy, the situation will be completely different. Almost 2/3 of costs are a reflection of up front investments and only 1/3 is due to operational costs. If prices remain equal to variable costs, it will be much more difficult to cover all costs. Or to put it differently, generators will be reluctant to invest in this zero-carbon future as they will be uncertain about how to recover their costs.

The high capital-intensity is mainly due to renewable energy, though the supply portfolio - with the balance coming from nuclear and fossil plants fitted with high-cost CCS systems - is more capital-intensive across the board. Looking at generation costs, overall CAPEX may be summarized as follows.

Table 4.2 *CAPEX 2010-50 per technology in different pathways (billion € in real terms)*

	Renewable energy	Fossil	CCS	nuclear	Total
Baseline	570	435	0	305	1310
80% renewable energy (1)	1995	30	155	180	2360
60% renewable energy	1515	45	310	360	2230
40% renewable energy	810	50	470	540	1870

(1) Remaining part half nuclear, half CCS.
Source: ECF Team analysis.

The situation may be sketched in a different way, looking at the variable costs of different technologies. In the current situation conventional coal or gas-fired power sets the price. Fuel and other variable costs of these technologies are 30 respectively 76 €/MWh (ECF Team analysis). Long-term marginal costs are 70% (CCGT) or 40% (coal) of short-term marginal costs. In a zero-carbon system, the situation is different. Variable costs of most renewable energy technologies are zero and quite often a tendency to over supply of intermittent wind and solar power may be observed. Relatively often the price will be negative or close to zero. Long-term marginal costs of nuclear are only 25% of short-term marginal costs (UK Climate Change Commission 2009). On the other hand, considerable additional capacity is needed for back-up and balancing. Peak prices will be set by open cycle gas technology (OCGT) that is easiest to start and stop, but has high variable costs (130 €/MWh). Therefore, peak prices will tend to be higher. In all, price volatility will be much higher in the zero-carbon pathways than in the Baseline and compared with what we are used to today.

In other words, it will be more difficult to earn the capital costs by means of prices equal to marginal costs. To put it differently, the difference between full and variable costs will increase.

Sunk costs are high. This situation exists already in contemporary infrastructure networks (roads, railways, gas pipelines). Experience in these sectors might help in finding a solution for this emerging problem (Helm, 2009b).

A branch of economic literature has shed a light on this future situation: the so-called 'missing money' problem, which has been discussed in the US electricity market extensively.[32] The 'missing money' argument is that competitive wholesale electricity markets and operating reserves do not and perhaps cannot credibly provide adequate net revenues to attract investment in generation. According to this view, spot wholesale electricity market prices for energy and operating reserves will simply not be high enough to cover the operating and capital investment costs (including cost of capital) required to attract new investment in capacity to support a least cost generation portfolio[33] (Joskow 2006 and 2008, Cramton and Stoft 2005, Shioshansi 2008). This is due to three factors:
- The specific elements of the electricity market: large variations in demand over the course of the year, non-storability, the need to balance supply and demand at every place and every moment.
- Most consumers are not aware of differences in prices at different moments and not able to react; therefore, demand does hardly react and the demand curve is almost vertical.
- No difference in reliability can be made between most consumers. Most individual reliability contracts cannot be enforced.

In the literature this problem has been associated with the impossibility to invest adequately in peak capacity, but it has a more general meaning. Observers of the US power market always had and still have a great concern that generation will not earn enough to invest (Joskow 2006, Cramton and Stoft, 2008). The 'missing money' problem may lead to very high prices in periods of high demand. Most US states have introduced price caps for such moments. These caps are politically understandable, but in theory increase the problem as a - especially low - price cap makes it even more difficult for a generator to earn his capital costs.

In general, two types of solutions have been investigated for the 'high CAPEX, low variable costs' problem. They have been coined 'bottom up' and 'top down' by Adib et al (2009).

4.3 Bottom-up approaches

In the bottom-up approaches it is argued that the actual 'energy only' markets have to be improved. An 'energy only' market is a market in which there is no policy instrument for stimulating capacity: the electricity price is the only driver of investment. In theory, several options exist to improve the 'energy only' market.

a. A usual solution to bridge the difference between average and marginal costs is to conclude a long-term contract. The contract binds the customer to pay the full costs. Consumers benefit by doing this if such kind of longer term commitment can reduce costs for investors and make solutions feasible that otherwise would have been impossible. Long-term contracts have been a common feature of the European electricity market, but they have been assessed more critically since the 1990s due to the potential harmful effects for competition. In a market with a high share of long-term contracts liquidity is relatively low. This is the reason why in general European electricity markets are judged to be more transparent and competitive than gas markets in which the share of long-term contracts is much higher.

[32] Another issue, not dealt with here, is that 'the' wholesale market does not exist, but consists of different entities, like spinmning reserves, frequency regulation or voltage protection.

[33] Joskow (2006) describes three problems of wholesale markets leading to insufficient investment: the 'missing money' problem; volatile prices due to insufficient long-term contracts; low price caps. All three problems come together in the capital intensive *Roadmap 2050* pathways.

Economic literature has a rather balanced view on the usefulness of long-term contracts (de Hautecloque and Glachant, 2009). Empirical research in the gas market supports the view that gas supply contracts linked to an asset specific investment are on average four years longer. In the power market, it has been demonstrated that long-term contracts facilitate entry when they are sufficiently long and when they can cover high volumes. Long-term contracts especially facilitate capital-intensive baseload technologies. Or to put it differently, without long-term contracts CCGT is the preferred technology. This is even more the case when most long-term contracts are up to 3 or 5-year contracts, whereas the economic lifetime of the capital stock in the *Roadmap 2050* pathways is 25 years or more. On the other hand, it is obvious that a too high share of long-term contracts dries spot markets out. The European Commission has looked at this trade-off and de Hautecloque and Glachant argue that, although some uncertainty remains, the Commission has developed a methodology that takes most of modern competition economics into account. This may be true, but does not solve the high capital intensity problem of 2050. The Commission does not view long-term contracts as such illegal, but considers the market position of the supplier, the share of customer's demand ties under the contract, the duration of the contracts, the overall share of the market covered by contracts, and efficiencies. In general, contracts between 2 and 5 years are considered to be the maximum.

It is clear that the aim to foster competition at this moment weighs more heavily than concern for investment. As the capital intensity increases, a more balanced approach seems necessary. This necessity to back investment by long-term contracts, not only for 5 but up to at least 15 years, has to weigh more heavily. It is suggested the Commission:

- To take the market design issues of higher capital intensity, needed to ensure a zero-carbon generation in 2050, into account.
- To continue to weigh interests of consumers heavily but include sustainability (defined in part as zero carbon power by 2050) into consideration.
- To consider long-term contracts up to 15 years or more as potentially beneficial.

b. Where such contracts are absent, investment tends to come with vertical integration. This might even be combined with long-term contracts as in the interesting case of the financing structure of the new Finnish nuclear plant (see Box 4.1). In a vertically integrated company generators own utilities or the other way around, or large consumers share ownership in new generation facilities. Interesting as the Finnish case certainly is for 1 or 2 plants, it is difficult to envisage how this could work for greater numbers. In the case of ownership by utilities this does not bind the final consumer who is still allowed to switch to another utility, but a close connection between generator and utility diminishes the overall risk for both of them considerably as the share of final consumers changing their utility is relatively low in Europe. But some observers have even suggested to finish retail competition to facilitate long-term contracts (Neuhoff and Twomey, 2008). Although retail competition and long-term contracts have inherent conflicts, it is not impossible to combine them as a situation with 100% long-term contracts certainly cannot be expected.[34] Especially the portfolio approach, in which both generation and retail companies have portfolios of different types of contract with regard to types of technology, customers and duration, make a combination possible (see point c).

Box 4.1 *The financing structure of the new Finnish nuclear plant*

An interesting example is the financing structure of the new Finnish nuclear reactor Olkiluoto 3, which combines long-term contracts and joint ownership. This was the first nuclear plant to be built in a liberalized power market. The owner is Teollisuuden Voima Oy (TVO). 60.2% of the shares of TVO is owned by a company which, in turn, is owned by various companies in

[34] On the contrary, the issue is which demand will ask for long-term contracts. If one doubts this will be case, some observers suggest to organise an obligation at the demand-side to conclude long-term contracts. See Box 4.4.

the pulp and paper industry. 25% is owned by the largest Finnish utility Fortum, the remaining share is owned by different local utilities. The project is financed on the balance sheet of TVO, which implies that loans are not tied to the project but to TVO as a company. This has allowed for 75% debt financing. TVO sells its output at cost to its shareholders. The project is covered by long-term contracts that effectively pass all risks on to the different shareholders and this was key in allowing for the high level of lower-cost debt financing.

Source: IEA, 2007.

c. Generators try to diminish their risk by obtaining balanced portfolios of different generation technologies. The European electricity market is increasingly dominated by a small number of internationally operating companies. These companies run a portfolio of generation technologies which hedges them to unexpected fluctuations in fuel costs. They are also the potential investors in capital-intensive renewable energy projects (offshore wind parks and in the future solar PV or large scale CSP projects), but will also continue to invest in CCS and nuclear energy.

d. A crucial aspect of an effective ‘energy only’ market is the absence of a price cap: prices have to be allowed to increase to levels that reflect full costs. These levels could be very high at some moment. The UK Climate Change Commission (2009) has investigated that by 2030 many plants would earn a significant part of their annual return over a few periods of the year with high prices. The consultant Poyry, which modelled the issue, argued that the price spikes needed to reward the risks for investment in peaking plant are likely to stretch the market design to the utmost. And, the Commission added, investors are unlikely to believe that price spikes will be allowed to occur. Therefore, transparency in regulation is crucial, because otherwise a self-fulfilling prophecy will arise: because investors do not believe that price spikes will be allowed, they don’t expect to earn enough, they don’t invest and the regulator has to conclude that additional measures are needed because the reserve margin is expected to become too low.

Additionally, no-regret measures can be implemented:

1. The most important of these is to stimulate demand-side response (DSR). The essence of demand-side response is that fluctuations in prices are felt by consumers to stimulate them to react to changes in prices. In the ECF analysis it is assumed that a large majority of the electric heat pumps that will deliver heat in buildings (see Box 5.4) are fully flexible and half of the number of electric vehicles (EVs) charge flexibly within one day. The majority of the assumed demand-side management is due to heat pumps, the remaining part mainly to EVs and a minor share to flexible appliances like air conditioning. Future opportunities for DSR in heat could be higher than in actual power demand as it has relatively higher demand peaks over the day. Therefore a potential of 20% DSR is considered to be realistic by ECF[35]. Although at this moment the estimate is that 1-2% additional reduction over the day in the peak might be achieved, with smart grids a 5% peak reduction in Europe might be possible: “The potential for greater demand-side participation in electricity markets is greater than ever” (Zarnikau 2009) (see Box 4.2). Such a broad approach is needed to reach the 20% demand response reduction which is assumed in the ECF analysis[36].
2. Secondly, other activities to decrease ‘regulatory risk’ will be necessary. These regulatory risks are highest for capital intensive projects with long gestation periods. By streamlining licensing and standardization of procedures within Europe the costs of getting permits could be decreased. One step further would be to offer a kind of ‘insurance’ against policy changes when a permit has been given. The government has to be a reliable partner in in-

[35] In the ECF pathways DSM is both peak shaving and following the supply curve of intermittent renewable energy.

[36] Authors like Joskow (2008) argue that without demand-side response energy-only markets are not capable of delivering adequate investments. With especially more demand-side approaches specific capacity mechanisms could eventually ‘fade away’.

vestment procedures. Moves in the right direction have been made in all European countries, but more can be done.

Box 4.2 *Demand-side response*

Volume 1 allows a maximum of 20% of the energy demand to be moved within the day, i.e. it does not imply demand reduction. Traditionally, demand-side activities have been labelled as Demand Side Management (DSM), driven by centralized utility load management. In competitive markets this has changed. In competitive markets demand response is related to load shaping and refers to strategies which can be used to increase the participation of the demand-side or end-consumers, in setting prices and clearing the market. When customers are exposed in some way to varying electricity prices, they may respond by shifting the time of the day at which they demand power to an off-peak period, or by reducing their demand through energy efficiency measures or distributed generation (see Chapter 5). To the extent they respond, the profile in the demand will be smoothed or follows the production of intermittent renewable power. This action will be rewarded by specific contracts (which is already the case nowadays for large industrial consumers), will back into prices and decreases the need for additional peak generation and infrastructure. Demand response is possible by real-time pricing. This can be system led (the system operator or a service aggregator signals the demand-side customers that there is a requirement for reduction) or market led (the customer responds directly to a price signal). Many estimates of the potential demand response exist and they differ considerably. The Florida Gulf power tariff is an example of a high figure with a peak-load reduction of 42% (Bilton 2008). The Nordic system operators estimate the additional economic and technical potential as four to five times as large as the current contracted demand response, up to 20 or 25% of the daily peak demand (Karkkainen, 2007) - mostly industrial processes and electric space and water heating. A recent FERC study, managed by the Brattle Group, indicated that in the US potentially 20% demand response is possible in 5 - 10 years and an achievable participation in that period is 14% peak reduction. By far the biggest untapped potential is residual, but also enterprises have larger possibilities than what is achieved currently (FERC, 2009). Technology with automatic demand response will increase the price elasticity considerably. Essential policies that are needed are e.g. hourly metering and billing for all consumers including the retail market or the possibility to adjust demand after closure of the market. New business models that aggregate the demand responses of small consumers could be developed. Regulation (to facilitate smart meters), standardisation (of rules and processes concerning smart grids) and changing utility-consumer relationships focusing on partnership and fairly shared costs are needed (see Chapter 5). Open standards are essential to guarantee interoperability of systems and devices (Capgemini 2008).

To sum up: within the actual market design several possibilities exist to reduce risks of investment:
- Less regulatory uncertainty decreases costs and improves the relative position of capital-intensive investments.
- Demand-side response decreases the need for specific peak capacity and lowers prices in peak periods, which will diminish pressure on politicians and regulators to impose price caps.
- Without price caps regulatory uncertainty decreases and the power market enables interaction between supply and demand.
- Long-term contracts of up to 15 years have to be considered more positively from both the security of supply and environmental (in case of the *Roadmap 2050* pathways) perspective.

Before turning to the top-down approaches, it will be investigated which lessons can be learned from European countries that already have high CAPEX, low variable cost markets. Three markets already are characterized by these factors:
- France has 80% nuclear and 10% hydro.
- the coupled Scandinavian market has 25% nuclear and 50% hydro.

- Switzerland has 45% nuclear and 50% hydro.

Current capacity in these markets has been installed mainly in a highly regulated context, before liberalization. Therefore, these markets do not prove that easy solutions are feasible in a market context. But some specific features of these markets may be observed:

- They have relatively high shares of interconnection. More interconnection makes it easier to level-off peaks and troughs in demand. This is one of the reasons the ECF pathways show a need for large additional investments in interconnections.
- In some cases a close interaction between generation and the state exists. French large generation companies have a considerable share of state ownership. The first new French nuclear plant that is under construction in Flamanville was ordered by the government as a 'demonstration plant' and in the second one the government strongly suggested the different shares of ownership. The European approach with a number of CCS demonstration plants is somewhat comparable and more future oriented as in this case a combination of European and national public-private activities underline the importance of investments in clean energy.
- But the most interesting examples are with respect to demand response. France has introduced electric water boilers for small consumers to be heated at night when overall demand is low. The Nordic market showed a high demand response in Norway when prices where high in 2002: 7% of demand decrease by small consumers due to a 30% price increase, implying a price elasticity of 0.23%, which is higher than other estimates (Jamash and Pollitt).

4.4 Top-down approaches

The main reason 'energy only' markets were not acceptable in most parts of the US was the unacceptability of price spikes, in combination with the suspicion that market power abuse was one of the main reasons for excessive temporary price increases. But the directions that have been looked at are important to investigate as they could help us in finding a solution for the 2050 zero-carbon electricity market problem.

Several capacity mechanisms have been introduced in practice and considered in theory. Only those that have been considered to be relatively successful or promising will be mentioned (for an overview, see Joskow 2006a, Shoshansi 2008, Glachant and Leveque 2009). Four different types of additional instruments have been implemented or are considered: capacity markets, capacity payments, auctions combined with obligations for retail companies, and an equivalent to the financing of infrastructure.

a. *Capacity markets or requirements*. Most deeply investigated are the examples in the Eastern USA: the PJM market, New England and New York state. Even Russia has introduced a capacity market recently, because a wave of new investments is necessary. The Russian approach has not been finalized yet, but will include separate markets for energy and capacity. In a capacity market load-serving entities (e.g. retail companies) are required to contract for a fixed percentage of reserve capacity. The capacity requirement is designed to achieve a target level of reliability. This mechanism is used (in different variants) in several regions in the US to solve the problem of high prices in peak demand. Locational pricing is used to stimulate capacity at the right place in situations of congested transmission lines, but could increase market power problems as well.

   The most advanced US capacity markets include forwards requirements, but may differ in the degree of centralisation of the approach: it might be that the load-serving entities have to demonstrate that they have acquired sufficient reserves which creates a bilateral capacity market (e.g. California ISO), or a central auction takes place (e.g. PJM, ISO New England). In that case, a capacity market is an auction in which the transmission operator auctions for additional capacity or demand response and these capacities are rewarded for availability.

The response by generators or demand-side measures determines the price. In most cases a price-cap is used. Capacity prices fluctuate considerably. As said, forward-looking elements have been introduced. The PJM market auctions three-year forward looking annual obligations for locational capacity under which supply (or demand reduction[37]) offers are cleared against a downward sloping demand curve: less supply is contracted when the auction price is higher. In this way a capacity market combines regulation (the capacity asked for) and market elements (the resulting price for capacity). A recent evaluation of the PJM market is rather positive about the outcome (Brattle Group, 2008), of which 25% is due to additional generation capacity, 20% to up rates of generating capacity, 10% to reduction of demand, 15% to decrease of 'export' to other regions and 30% to cancellation of planned retirements. The share of demand reduction is not that large, but led to a considerably lower auction price (Gottstein and Schwartz, 2009). In general, the social welfare of demand response activities is considered to be larger than the costs (Walawalkar, 2009). Advantage is that demand-side measures can play a role as reserve capacity, but due to lower peak prices 'ordinary' demand response will be lower.

In theory, a capacity requirement or market delivers good results in stabilization of investment during a business cycle (De Vries, 2005). This could be improved further by increasing the length of the forward looking elements. In the New England (ISO-NE) market they are extended to five years for new generation, but a capacity market will only stimulate capital intensive base load capacity when investors are certain that the reward will remain in place for at least ten years (this argument is comparable with the case for long-term contracts).

Although the basic features of capacity markets are simple, they have to be designed carefully and tend to become more and more complicated. "The essential elements of (the improvement of the PJM market in 2007) include an annual market, a forward market, locational capacity markets, scarcity pricing of capacity via a defined demand curve, explicit links to the energy and ancillary services, incentives to provide reliability, and clear market power rules including a must offer requirement" (Bowring, 2008). This is inevitable due to the complex nature of 'the' wholesale market. On the other hand, a more centralised approach has led to transparency, reduced transaction costs and improved market monitoring (Brattle Group, 2009).

b. *Capacity payments* (Chile, Spain) or strategic reserves by TSOs (Sweden) are a solution for the capacity problem in which the TSO itself plays an active role. This is especially the case with the strategic reserve in which the system operator maintains a reserve of power generation units that it dispatches when the reliability of the supply is threatened or the prices surpass a threshold. In the capacity payments solution an independent agent - such as a regional wholesale market operator or TSO - pays generators for keeping capacity available. Variants have been found in between these examples, in which the TSO has extended his responsibility to guarantee the reserve by contracting especially demand side response with large consumers in case this was deemed to be needed (The Netherlands). Pure capacity payments have met criticism because of possibilities for market abuse[38].

c. *Auctioning of new capacity and obligation for retail companies.* This type of auctioning is used in Latin American markets (Brazil, Chile, Peru) and especially the Brazilian case is well known (Hermes de Araujo, 2008). It is interesting, because 85% of power generation is by hydro, which in its cost structure might offer a view into the European future. Prices are

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[37] Two types of demand reduction exist: energy efficiency improvement (e.g. by stricter standards for buildings than formally required) which have a lasting effect and demand response, in which demand changes from the peak period of demand to periods of lower demand (e.g. by temporary switching off of air conditioning).

[38] Purely financial instruments will not be dealt with. Some observers value them very favourable (Wolak, 2004), but most energy economists are of the opinion that by themselves they are incapable to solve the high capital intensity problem (Joskow, 2006a; De Vries, 2005).

volatile. New investments are extremely difficult to finance as prices may be very low for several years. In the early 2000s huge shortages emerged as the energy-only market had not been capable to enable investing an equivalent to the increase of demand. Extreme rationing (up to 20% of demand) and other urgency measures were necessary to attain a short-term equilibrium. In the new model, introduced in 2004, distribution companies have been obliged to contract 100% of the expected demand for five years ahead in a mix of hydro and thermal. Central auctions are held for 15 (thermal) or 30 year (hydro) contracts in which distribution companies pool their demand. Effectively, a single buyer has been introduced for new capacity. This offers additional income for new investments. In this way especially small consumers are hedged against price volatility and a reliable supply is offered. The auctions attract considerable investment. For example, in the June 2006 auction Brazil sold for almost $ 21 billion of long-term electricity contracts (Bloomberg, 2006). Next to this 'pool' aimed at captive customers, large customers are free to invest in generation. A problem might be that 'ordinary' investments are less attractive when the certainty exists that in case of scarcity these auctions will be organised. The market design is also considered to be complicated and requires considerable administrative and regulatory expertise (Kamacharya, 2008). Finally, a way has to be found to oblige the retail companies to contract the new capacity, which is more complicated in Europe than in Brazil because of the European competitive retail market (especially in the case of vertically bundled companies with retail and generation activities)[39]

d. A different approach is the comparison with infrastructure (Helm, 2009b). It cannot be excluded that eventually *some generation activities have to be treated as 'infrastructure'* (which has a somewhat comparable cost structure as generation in the *Roadmap 2050* future).This does not mean that it is suggested to return to the 'old' model, but a stronger role for regulation in the market structure could be considered (see also Box 4.4). In infrastructure tariffs are regulated. The regulator looks at operational efficiency by means of a RPI-X formula (see Chapter 5.2) and investments are approved by looking at the regulated asset base (RAB) valued at a regulated capital value (RCV). In this way the RAB might become the long-term contract between investor and customers. This looks like a considerable change from the actual situation in which generation is a market issue and infrastructure regulated business. But intermediary steps have already been set. The UK has organised an auction for infrastructure to offshore wind turbines, which is not fundamentally different from the auction to build the offshore parks. The opportunity given by the EU Electricity Directives to start an auction for additional capacity has never been used yet and certainly will meet objections[40], but demonstrates that the idea has never been that the European power market will solve all problems without active government intervention.

Box 4.3 *Dynamic performance of different market designs: examples of modelling results*

Although it is still uncertain how different market designs will perform in a European context, interesting modeling has been done that gives an insight into possible outcomes of different designs under uncertainty (De Vries and Heijnen, 2008).

Starting point of the analysis is that a prudent strategy for investors is to invest less than the social optimum. Investing 'too much' implies a risk of a 'bust' phase in the market in which investors cannot recover their total costs. The risk of investing 'not enough' is limited to losing some market share. If competitors make the same risk assessment supply will be less than the social optimum, which will lead to higher prices.

De Vries and Heijnen developed a model to assess the effectiveness of different capacity

[39] These 'holdings' are complicating the Brazilian market as well. Distribution companies are allowed to buy up 30% of their electricity from their own subsidiaries (OECD 2004).

[40] An evident objection is that if the possibility to auction for investments paid by the government becomes serious, no ordinary investment will take place anymore as all investors will wait for the auction.

mechanisms in the presence of uncertainty regarding demand growth. An energy-only market had a relatively high average price with extreme standard deviation (price volatility) and an almost structural shortage of investments. A capacity payment mechanism leads to a lower price, less volatility and much less shortage. A politically difficult aspect of this approach is that capacity payments also have to be continued in times of excess capacity. Pricing of operating reserve beyond what the TSO needs to maintain system stability appears effective with respect to reducing the risk of shortages, but does little to dampen volatility and leads to a higher average price. A capacity obligation or market can effectively dampen the investment cycle, leading to high reliability and on average lower prices. Interestingly, an energy-only market with market power seems to have a stronger incentive to invest somewhat more than in case of full competition, as oligopolies tend to deter new entrants and to diminish the risk of political intervention. An oligopolistic market-only design - modelled with a 10% higher price than the long-run marginal costs - leads to higher investments, less price volatility and a slightly dampened investment cycle. De Vries and Heijnen think that this situation reflects the actual European electricity market and explains the limited interest in developing capacity mechanisms.

Their overall conclusion is that, because in the presence of uncertainty the interests of companies and consumers diverge, capacity mechanisms appear to be effective instruments to realign these interests. None of the capacity mechanisms led to an increase in average prices.

It is clear that no final judgment is available which scheme delivers most at which costs.It will depend on the actual market design and general statements possible are impossible. Even advocates of capacity markets conclude that “the market designs are still relatively new and rapidly evolving, and have not yet been tested over the full investment cycle of capacity resources” (Brattle Group, 2009).

Several preliminary conclusions may be drawn:
1. The theoretical base that an energy-only market is incapable to attract a level of generation that is optimal from a point of view of society seems quite strong, as long as demand-response is weak and no specific reliability contracts are possible (Joskow 2006a)[41]. Available empirical evidence in other parts of the world supports this conclusion. In theory, a capacity market solves the ‘missing money’ problem.
2. The IEA (2007) warns against capacity payments as they are closely linked to price caps: “Price caps have necessitated additional incentives by imposing capacity obligations and capacity markets. So far, capacity markets have been a poorly prescribed medicine with serious negative side effects” (IEA, 2007). It is indeed better to remove price caps, but the analysis seems to be only partly true, as they are not the only reason for the introduction of capacity structures (Joskow, 2008).
3. The jury on relative costs and benefits is still out. Even when additional capacity has been realised, it has to be confronted with the additional costs. Further, a problem is that capacity instruments might ‘crowd out’ other investments: if the certainty exists that an auction will be held, who will invest in ‘ordinary’ generation?
4. Theoretical analysis and modelling suggest that capacity markets seem to perform better than capacity payments or ‘price adders’ in stabilisation of the investment cycle and in reaction to temporary crisis (Lijesen 2003); capacity payment mechanisms seem an effective means to stabilize the income of incumbent generators, but there is no clear evidence that such payments encourage investment in new generation.

A remaining issue is how *urgent* this debate is. The organization of transmission operators ENTSO-E drafts every year a ‘system adequacy forecast’. ENTSO-E was established in July 2009 and the first system adequacy forecast was published in February 2010, with a forecast up to 2025 (ENTSO-E, 2010). It foresees a safe balance of electricity generation and demand in the

[41] However, this is also related to the number of players on the power market: the more, the closer the outcome is to the social optimum (Castro-Rodriguez, 2009).

power system up to 2020, but narrowing margins between generation capacity and demand from 2015 if there is no additional investment. However, the forecast acknowledges that demand growth probably has been overestimated (due to the effect of the economic crisis, which has only partially been taken into account), whereas the reconsidering of the nuclear phase-out in Germany and Belgium and the National Renewable Energy Action Plans (see Chapter 3.5) have not yet been taken fully into account. Nevertheless, it is expected generation capacity of especially wind energy will increase fastest, due to ambitious national policies. Gas-fired capacity will increase as well. Hard coal capacity decreases considerably in the 'conservative' scenario, but will remain stable is the 'best estimate'. In all, the system adequacy does not seem to be in danger, but the *combination* of the need to retire high carbon capacity, the regulatory uncertainty about nuclear and CCS and the uncertainty about CO_2 prices leads to some urgency in the need to consider an adequate market design. This may be illustrated in another way. Of the current 3250 TWh annual European power production, some 700 TWh are expected by ECF to be generated in 2050 by already existing capacity. The remaining current plants will be shut. But of the 2020 stock another 830 TWh is assumed to be produced by 2050. In other words, to the extent the new capacity of the next decade is locked-in in unabated fossil fuel, this will remain a potential problem up to 2050.

However, as shown in Table 4.2, some three-quarter of the high CAPEX problem is due to high upfront investment costs of renewable energy. One might argue that as long as the incentive system of renewable energy is stable and delivers, the remaining investment problem is not so urgent as long as lock-ins are excluded. This is the case when all fossil fuel investments have to be capture ready (coal) or can be assumed to be retired before 2050 (gas). Furthermore, prices will stay high as long as gas- and coal-fired generations are the marginal suppliers in the merit order, which will remain the case in the near future[42].

It may be concluded that the current market arrangements will not deliver a high capital-intensive low-carbon system. An improved ETS is extremely important, but as feed-in tariffs or alternative systems will gradually fade away when the cost of renewable electricity will decrease, the then existing market design has to be fit for purpose. Time has come to consider whether additional technology-neutral instruments could be useful. If we aren't prepared for an eventual high-capital scenario, the possibility that we will fall back to the Baseline is large. One has to realise that a process of discussing, designing and testing new market mechanisms will take at least three years. It is much better to start this discussion at a moment in which market conditions are relatively benign, rather than when an emergency is already within sight. Therefore, this debate has to start now. *To be prepared for a next stage* in which the capital intensity issue really becomes urgent, a study is proposed: The European Commission could organise a serious study of pros and cons of different capacity mechanisms, to be prepared for the future. It would be useful if the outcome is available on time, to draft eventual proposals and decide before 2015.

Box 4.4 *More interventionist energy policy in Britain to be expected*

UK Energy and Climate secretary Miliband announced in February 2010 that for the longer term. Britain will need a more interventionist energy policy. "The scale and upfront nature of the low carbon investment needed is likely to require significant reform of our market arrangements to deliver security of supply in the most affordable way" (Guardian, 3 February 2010). This statement was made in reaction to a report by the British energy regulator Ofgem that presented the conclusions from a year-long study of whether the current arrangements in Great Britain are adequate for delivering secure and sustainable electricity and gas supplies over the next 10-15 years (Ofgem, 2010). The scope of the report is comparable with the ques-

[42] The consultancy Pyory modelled for the UK Climate Change Commission that even in a scenario in which 60% of generation is produced by low-marginal cost plants by 2030, CCGT continues to set the UK price in most of the time. Even in 2030 high prices and large rents could be expected in the UK (UK Climate Change Commission 2009).

tion raised in this chapter (but includes gas security). The key issues identified were the need for unprecedented levels of investment in clean technologies against uncertain future carbon prices, weak price signals to invest in peaking capacity, a risk to lose competitiveness and the relatively more specific UK concern with gas supply. Ofgem "did not consider that leaving the current arrangements unaltered is in the interest of consumers" and presented five possible packages.

The less interventionist package A, *Targeted Reforms*, is comparable with what this document calls an improvement of the energy-only market with a slightly different focus. Whereas this document pleads in favour of strengthening the EU ETS cap, demand-side response and more long-term contracts, Ofgem proposes a minimum carbon price, an improved ability for demand side to respond and improved price signals (this implies making the allocation of reserve costs more reflective of system tightness). Somewhat further goes package B, *Enhanced Obligations*, in which energy suppliers would be obliged to demonstrate that they had sufficiently contracted supply to cover the future energy demand of their customers against some pre-defined security standards, in combination with an obligation for the TSO to make certain provisions in advance. This package is somewhat comparable with a capacity market and capacity payment as sketched before in this report. Ofgem's package C adds central capacity tenders for renewable energy to package B, which would replace the current UK Renewable Obligation. Package D broadens this to capacity tenders for all generation capacity, with separate tenders for long-term capacity for low carbon generation and shorter term capacity tenders as in the US forward capacity markets. The most interventionist package E is called the *Central Energy Buyer*, in which all future investments are co-ordinated through a single entity.

Ofgem does not make a choice between the packages. It mentions risks related to packages A - C which maybe would not deliver additional clean capacity, and packages D and E, which could stifle innovation, lead to overinvestment and biased central choices, whereas current EU legislation at least limits the implementation of package E.

The UK government is expected to announce proposals in the coming months.

4.5 Regional roadmaps needed

One cannot assume that the market will deliver a low carbon power system 'by itself'. By means of the specific low-carbon technology approaches as sketched in Chapter 3 governments strongly influence the market (see Box 5.5). But gradually feed-in tariffs and premiums will decline or fade away and the price of green certificates probably will decrease as the cost difference between market prices and costs will decrease. Demonstration projects of CCS will lead to a cost decrease as well and gradually the CO_2 price takes the lead in stimulating low-carbon investments. The ETS system will take over as a general incentive, but does not differentiate between technologies. Still, governments have their preferences in what they consider to be an optimal fuel mix. These preferences also depend on the expectations of the benefit of specialisation in industrial policy. The UK prefers offshore wind, nuclear and CCS, France nuclear and renewable energy in general, Spain solar PV, wind and CSP, and so on - partly because these countries think they have an industrial opportunity in delivering these technologies. This will remain so in the near future.

It will be sketched in the next chapter, the interaction between generation and infrastructure becomes more and more important and infrastructure has to play a less 'passive' role in the future. This is relevant both with regard to distribution (smart grids) and transmission. Transmission is also a cross-border issue and exceeds the boundaries of individual countries. By means of market coupling national markets are integrating; implicit auctions include both transactions of power and scarce interconnection capacity. We are now bordering the question of *market vs. planning*. In our view the market will remain the dominant structuring mechanism to enable a zero-carbon power system. But the market will not be able to deliver without some kind of guidance by governments. This specific guidance could be indicative, but the end result (zero carbon power supply by 2050) could be mandated explicitly, either through a series of compulsory intermediate targets or through other mechanisms. Governments, investors and other stakeholders have to interact more closely as they need each other to make effective decisions. As a start of this indicative, interactive ‘planning process’, it might be extremely useful for governments to draft *joint regional roadmaps* of the fuel mix they envisage. In this way they may sketch which priorities they have and how they foresee e.g. the continuation of renewable energy when specific incentives have ended. In the beginning, these visions will be mainly national, but gradually joint - including those of neighbouring countries - considerations could be added. The EU has a role to play in encouraging these national and regional processes, directly supporting them with e.g. funding for the required resources, or even requiring that they be carried out, with discretion left to member states on the specific format and venue. Of course, such a roadmap has to be drafted in close cooperation with generators, as finally they are the actors who have to invest. These visions could be the foundation for investments in infrastructure (see Chapter 5 and Box 5.5). Existing regional platforms could be a starting point for discussions and technology policy. In this way a forward-looking approach is possible, using all elements of the back-casting pathways. The regional roadmaps do not have the power of formal investment decisions but - especially if they have been drafted in cooperation with stakeholders - will certainly be taken into account by private investors. They could become the basis of infrastructure planning, and they could be used in the contacts between governments and regulators and between central and local governments (comp. Boot et al, 2010). When the regional roadmaps have been accepted by the national parliaments and certified as compliant by the EU, they will further improve the stability of government policy and diminish regulatory risks.

4.6 Conclusions

One has to prepare for a significant change in the costs structure of generation, which is a risky affair for all stakeholders. The most important message of this Chapter is that governments *can* decrease risks. They can do this (comp. IEA, 2007):
- By creating a stable and competitive investment framework.
- By giving firm and long-term direction on climate policies, including by drafting regional long-term roadmaps on the preferred fuel mix in close cooperation of relevant stakeholders.
- By continuing the approach taken in the Third Energy Package, ensuring that independent regulators and system operators establish transparent market rules.
- By refraining from price caps.
- And by implementing efficient procedures for those types of new zero-carbon power generation which are preferred in the regional roadmaps.

More in particular, the following proposals have been made.
1. It is too early to judge to which extent an improved ‘energy only’ market (in which capacity is not rewarded separately) is not able to deliver the investments in the power system that are needed, but it is nearly certain that at some moment the actual market design will be insufficient. It is important that flexible and uncapped prices are allowed and long-term contracts can be used to facilitate financing structures in capital intensive generation - the long-term contracts have to be of durations sufficient to support permanent financing for new low-carbon capacity. Reduction of regulatory risks leads to a cost decrease in all cases. At some moment additional capacity mechanisms might become necessary. To be prepared for a lack of investment a serious study of pros and cons of capacity mechanisms could be organised by the European Commission that would suggest conclusions before 2014.
2. Demand-side response has to get more policy attention, as it improves reliability of the power system and diminishes the need for additional investments.
3. Governments are advised to draft ‘regional roadmaps’ of the preferred fuel mix, aiming at concrete proposals on how to actually attain a zero-carbon power system. The EU has a role to play in encouraging these processes, directly supporting them or even requiring that they

be carried out. These roadmaps could be formulated in close cooperation with relevant stakeholders, as these are the ones who have to invest (generators), pay (consumers), enable (grid companies, local governments) or are otherwise relevant stakeholders (NGOs). The roadmaps will gradually become regional as regional markets will unite gradually. This will be a step by step process from purely national to more regional approaches. The EU has a role to play in encouraging these national and regional processes, directly by supporting them with e.g. funding for the required resources, or even requiring that they are carried out, with the discretion left to Member States on the specific format and venue. The roadmaps could be the basis for infrastructure policy as will be sketched in the next chapter. These roadmaps are no ‘plans’, but may increase transparency in licensing and stability in the degree of government support to zero-carbon generation investments. This will diminish regulatory risks, which are larger in a more capital intensive system.

5. Does a low carbon power system need a new market design? The role of infrastructure

5.1 Introduction

Large investments are needed in infrastructure networks. A regional concentration of specific types of generation will occur: solar PV in Spain, offshore wind around the North Sea, coal-fired plants in places where carbon storage can take place and cooling water is available. Transmission grids will be enlarged considerably, both to improve interconnection between regions and to balance the increased share of renewables. It will be investigated how the necessary infrastructure investment can be enabled in the most cost-effective way

It will be considered in which way regulation can play a role and how regional markets - close cooperation between several countries - could be a first step towards a European approach. Next, the challenges for balancing and storage are dealt with. The final question addressed in this the chapter is which changes are needed in the distribution grid - smart meters, demand response, distributed generation and finally smart grids. Regulatory issues, economic signals and innovation have to play a role in attaining the necessary paradigm shift in distribution[43].

Section 5.2 gives an introduction into infrastructure issues, 5.3 deals with transmission, 5.4 with storage and 5.5 with distribution. Section 5.6 concludes the chapter.

5.2 Infrastructure: general issues

Investments in transmission and distribution are estimated to amount to about half of total investments in the global power sector (IEA 2007). As Europe has a well-developed grid system, their share is somewhat lower: in Europe, it is expected that 15% of total investments in the power sector in a Business as Usual scenario for 2005/7-2030 takes place in transmission, 20% in distribution and 65% in generation. These grid investments are already somewhat higher than their respective shares in current costs. Although all estimates are highly uncertain, an indication could be the IEA expectation of needed investments of 200 billion € in transmission and 300 billion in distribution in slightly more than 20 years up to 2030 (IEA, 2008a). PBL (2009) expects overall investments in transmission and distribution grids to be one third higher in a low-carbon scenario compared with a Baseline scenario. These investments will predominantly take place in a regulated business.

Electricity networks are considered a natural monopoly and hence they are regulated in terms of pricing, access and other specific aspects such as the quality of service or energy losses. Most countries have already implemented incentive regulation to remunerate grid companies. These schemes acknowledge the existent asymmetries of information between the regulator and the grid companies and, in theory, seek for promoting efficiency in the long-term by indexing the remuneration of the network to the service instead of incurred costs. Incentive regulation is either through yardstick competition (benchmarks) and/or price caps (referred to as RPI-X regulation)(Haney and Pollitt, 2009). Under RPI-X and benchmark regulation, the grid companies' revenues are limited or capped ex ante for a number of years. In order to do so, regulators need to compare the efficient investments and operational costs and/or benchmark the behaviour of

[43] This chapter is based upon ECF analysis which is considered to be robust. An earlier ECN analysis concluded that four major electricity developments could be identified in Western Europe: (1) a further increase in electricity demand; (2) an increase in the share of renewable energy; (3) a gradual shift towards decentralized generation and (4) a transition of national self-sufficient electricity systems towards a European system (Van Werven et al, 2006).

different companies. RPI-X often implies that network companies are allowed to increase their tariffs for a certain period in the future with the consumer prices minus a figure to stimulate efficiency improvements; this consists of a general figure and a specific one for each network separately that depends on the outcome of the benchmarking.

This approach has improved efficiency of the networks. Costs have been reduced considerably (Jamash and Pollitt, 2008). Gradually some modifications have taken place. The quality of the network became part of the benchmarking and several regulators allowed small uplifts for R&D and innovation. Recently, however, one may observe more reflections whether this approach still is adapted to future challenges. Two aspects in particular play a role (comp. Ofgem 2009 and NMa 2009):

- In the next decades more investments are necessary as the majority of networks has been built in the decades after the Second World War and their lifetime has ended. A better investment climate is necessary.
- It would make a difference if grids explicitly get the function of facilitating sustainability in a general way. Actual regulation does not look specifically at sustainability issues. Sustainability could be promoted more explicitly, either with regard to energy efficiency in distribution grids or renewable energy (mainly wind in the transmission grid and solar and small biomass in distribution grids in the near future). Regulators have announced, e.g. in the context of the World Forum on Energy Regulation, to be prepared to play an active role in the advancement of sustainability (WFER, *Statement on Climate Change*, 2009). This would only have a real meaning if it would be based on a non-trivial definition of sustainability, i.e. one that includes the need for full decarbonisation of power by 2050.

As grids are regulated, consumers and producers will eventually pay the necessary investments. This might lead to an increase in tariffs that could be considered too high. It is therefore extremely helpful that support in financing by the European Investment Bank (e.g. by the Marguerite Fund) is making progress.

In the current market model infrastructure has to follow generation and consumption; networks play a passive role. They are obliged to connect the generator and consumers. Due to long lead times this does not always work smoothly in practice. One of the challenges in connecting new generation is that the lead times for developing new network infrastructure may be longer than the lead times for constructing the generation, which is mainly due to authorisation and consent issues (CEER 2009). Small CHP can be planned and installed in between half a year and one full year; strengthening of the distribution grid and the construction of a transformer station often takes 2 to 3 years. This leads to congestion in the distribution grid. The same occurs in transmission. France and Spain acknowledged the need to connect the two countries more intensively for many years. Due to local opposition to new transmission lines new investment could hardly take place, however. It easily takes 10 years or more to plan and construct transmission lines.

The specific situation of renewable energy within EU member states has been looked at by the recent EU Directive on Renewable Energy (2009/28/EU of 23 April 2009), which obliges member states to offer renewable energy admission to the infrastructure and priority in case of congestion. Priority for renewable energy has three aspects: financial, balancing and international aspects (Boot et al, 2010).

In the feed-in tariff the network operator is obliged to buy all renewable electricity against a fixed sum and the operator has to guarantee the balancing, the costs of which are socialised on all consumers. This is a radical way of prioritizing. In the feed-in premium renewable energy is still part of the electricity market but the average of higher or lower balancing costs is compensated by the premium (cf. Chapter 3). Renewable energy has no priority in balancing of the grids. In the so-called programme responsibility of operators no exception has been made for green electricity. This is a reason why more accurate forecasts of wind energy will further improve their relative situation.

Interestingly, the Directive on Renewable Energy has no provisions for the international transmission. TSOs are restricted in prioritising renewable energy as only safety of the international grids is an acknowledged reason to take action. In fact, one may observe an inconsistency between market integration and a sustainable energy policy. Another issue, dealt with in Chapter 3 in a more general way, is that no solid reason can be found to prioritise only renewable energy but not CCS (as both are on a learning trajectory).

In several countries the question has been raised whether it is possible to choose ex ante an 'optimal' grid structure. This is a fundamental issue. On the one hand investors are asking for stability, but due to inevitable uncertainties a degree of flexibility is needed as well. Examples of the relevant policy discussion in two countries will be given because they are comparable and have a more general meaning for Europe. The UK LENS approach distinguished 5 scenarios to be prepared for different scenarios, of which we will mention three, to be prepared for different futures (Pollitt 2009). They included:

- Emphasis on large transmission grids with TSOs at the centre of network activities.
- Distribution System Operators taking a central role in managing the electricity system (system management including generation and demand management).
- Self-sufficient micro grids.

In our view the self-sufficiency approach is inefficient as it fails to use the comparative advantages of power generation in Europe, so decreases the opportunity to attain a zero carbon power system and leads to higher costs than necessary. But the increased roles of the TSOs and DSOs have to be combined into a multi-purpose network[44].

A comparable discussion took place in the Netherlands, where the government distinguished three network scenarios (Dutch Ministry of Economic Affairs 2008):

- Emphasis on nuclear and clean coal.
- Emphasis on decentralized generation.
- Emphasis on offshore wind with gas turbines offering the necessary flexibility.

The Netherlands government decided not to choose a favourite scenario, which was criticised in Parliament. The Dutch government was right, however. In reality both centralisation and decentralisation will take place. Without offshore wind, large-scale solar PV and other centralised options a nearly full decarbonised power system will not be achieved. But at the same time smart grids are needed to stimulate demand response, even more when heat pumps and electric vehicles will diffuse to mass use. We don't know how fast these developments will happen, but in a sustainable scenario *both* considerable transmission and distribution investments are needed. In conclusion, the apparent choice between stability and flexibility is a false one. Both are needed, even when this might look like a more expensive option in the short-run. Without stability no investments can be made, but without flexibility inherent uncertainties - which decisions will be made by which parties and which technologies will be preferred at which moment - are neglected.

5.3 Transmission

To facilitate the transformation to a zero carbon power system large investments in transmission are needed. The higher the share of renewable energy - especially for offshore wind - the more transmission is needed. This has both a direct and an indirect cause. The direct cause is that off-

[44] The multi-purpose network was the fourth scenario of the LENS approach. The fifth one put emphasis on ESCOs (energy saving companies).

shore wind needs dedicated infrastructure. The indirect cause is that the intermittency of wind and solar energy requires more sophisticated balancing that can be partly solved by improved transmission. The larger a region in which the intermittency issue can be solved, the easier it is. On the other hand, more demand side management decreases the need to invest in transmission grids. Although the sums are large (Volume 1 analysis computes an additional investment in transmission between 9 European regions of 71 - 84 billion € for the 60% renewable energy scenario and 105 - 139 billion for the 80% scenario), this is probably less than 5% of overall investment in the European power system.[45] Moreover, the speed in which additional transmission has to be built does not seem to be outside reach. Volume 1 estimates that interregional transmission capacity has increased with 17% in 2000-10 and has to increase further with 23% in 2010-20 in the 60% renewable energy pathway. The task for the coming decades (in the this pathway and with 20% demand-side management or better demand response) is a quarter higher than what has been achieved in the recent past. The largest increase has to take place between Spain and France. In the 60% renewable energy pathway with 20% demand-side response, the overall interregional transmission has to increase from the current 34GW to 87 GW, but the Spain - France interconnection must increase from 1 to 32 GW. Actually, the European transmission enlargement is a mainly regional issue, which probably makes it easier to achieve by means of the regional market approach (see Box 5.2). Capacity utilisation could be between 60 and 90%, which is higher than today. Such utilisation figures mean the capacity is used day and night and across the seasons. Today, transmission capacity is utilised most to meet peak demand within regions.

This impressive increase of transmission implies a real change towards one ‘European transmission grid’. Countries and regions have to trust each other and have to be prepared to use each others comparative advantages. This may sound self-evident and it should be, but implies further steps on the road towards a joint European perception of reliability and security of supply.

Box 5.1 *Wind energy, networks and regulation*

Most transmission infrastructure investments are related to wind energy, both directly (offshore grids) and indirectly (balancing). European energy regulators consider three areas in particular where integration of wind energy needs to be included in policy decisions:

- Electricity market arrangements, including the benefits for wind generation of allowing bids or declarations closer to real-time and the importance of within-day markets and cross-border trade with the aim to have a common merit order, as well as balancing by TSOs from national to regional markets.
- Network access arrangements, such as the rationale for different forms of charging for connection and how decisions are made to extend the network to accommodate new generation, including locations remote from existing infrastructure and demand.
- The concept of super grids, and the challenges in harmonising the range of different policy and regulatory treatments, eventually on a broad scale and initially in regional projects. The first ones will be the Kriegers Flak project between Denmark and Germany, and the step by step approach towards a North Sea offshore grid project. Nine countries around the North Sea (including France, Ireland and Luxemburg) are developing a project to invest 30 billion € in an offshore wind grid. The aim of the 10 year plan is to link offshore wind farms along

[45] Overall investments are highly uncertain and estimates vary greatly. The IEA (2008a) estimates in a Reference scenario 1000 billion € for generation. 200 billion € for transmission and 300 billion € for distribution in the period 2005/7 - 2030. The Consultancy Roland Berger assumes strong climate policies need some 1400 - 1900 billion € investment in generation, and in a scenario without strong choices between either transmission or distribution grid improvement some 1400 - 2000 billion € in network investments in the period 2010-30 (Boot et al, 2010). This shows that the sums are huge, but the infrastructure costs are only a part of a larger picture. PBL (2009) expects a low-carbon pathway will need 1000 billion € investments more in transmission and distribution than the 2000 billion € needed in the Baseline. A US study concludes that in order to transform America’s power industry, three times as many investments are needed in distribution networks compared with transmission (The Brattle Group, 2008). But even this is uncertain as new investments in distribution grids are needed anyway to upgrade the old grid.

the coasts of Germany, the UK, the Netherlands and Belgium with wind and solar power systems on the European mainland. Leading European power companies are closely involved, as they have to invest in the wind turbines (aiming for 100 GW), as are network companies who have to operate the grid.

- The North Sea could be an interesting experiment in establishing a de facto Regional Transmission Operator. The US has positive experience with the ISO and RTO models, in which common operations are established without joint ownership[46]. Without a largely common approach it is difficult to see how procedures and operations could cooperate effectively. This would impede a cost-effective development of the North sea grid.
- European regulators tend to conclude that it is no longer practical to consider reneables, infrastructure and electricity markets as separate topics - it is essential to consider their interaction (CEER, 2009).

At this moment national regulatory authorities (NRAs) have to approve the interconnection investments on a case by case basis. These are difficult processes that do not lead to optimal results from an integrated network point of view. A first condition for an optimal approach is that investment decisions about interconnection are based on structural reasons, such as differences in primary resources, fuel mix and load patterns between countries. Price differences that result from the difference between regulatory structures may not be structural and therefore cannot justify this kind of investments. A case by case approach looks at high utilisation of individual lines, whereas an optimal network approach might lead to *lower* network utilisation of several lines (cf. de Jong et al, 2009)[47]. In June 2009 the new Agency for the Cooperation of Energy Regulators (ACER) was established, acting mainly as an advisory body, a forum for cooperation between regulators. The current Regulation EC 714/2009 refers to economic benefits and security of supply, but does not include environmental targets as criteria to be considered when assessing investment proposals. National regulation should facilitate the process of huge investments also from a European point of view. ACER should actively promote the development of a strong, reliable and sustainable European interconnections infrastructure system. This would include the facilitation of all necessary interconnections. Currently it does not have that mission. Its main focus is to give opinions and advice to the European Commission and ENTSO-E, the European Network of Transmission System Operators for Electricity. Mandatory powers for ACER are limited to specific cross-border issues, notably with regard to conflicts between neighbouring regulatory authorities and - perhaps more importantly - on exemptions for new cross-border infrastructures.

Box 5.2 *Regional Markets*

The initiative to create regional markets as a first concrete step towards a European approach was formulated by ERGEG in September 2005. A closer cooperation between EU member states has emerged in regional markets, such as the Nordic market or the Pentalateral Forum of France, Germany and the Benelux. A recent analysis showed that regional initiatives have been effective in implementation: promoting a culture of regional cooperation, at different speeds, with pilot testing and spreading of best practices. However, what is lacking is a ‘reference model’, a kind of central direction, to be able to check different regional approaches.

The central issue in the most recent Florence Forum meeting in December 2009 in Rome was how to combine a bottom-up approach of the regional initiatives, that might be in particular helpful for capacity expansion and investments in wind energy, with the top-down approach of

[46] Independent System Operators (ISO) and Regional Transmission Organizations (RTO) are operators of the transmission system and do not own any infrastructure assets. A key benefit of the RTO structure is the capability to integrate system operations and wholesale markets over large regions, which is the task of the ISO for a smaller area. In practice, cooperation probably could evolve form the ‘ISO’ to the ‘RTO model’.

[47] This is one of the reasons an Inter-Transmission System Operator Compensation Mechanism (ITC) has been drafted by the European Commission to receive a more formal status, that shall provide for compensation for the costs of hosting cross-border flows of electricity, including providing cross-border access to the interconnected system.

the 'reference model' (Mercados 2009). It also was suggested to give more political guidance by means of a group of government representatives.

A main proposal in the Forum was to continue the regional initiatives with increased strength, concentrating on capacity expansion of transmission and pilot testing of new approaches (e.g. market coupling and regionally coordinated balancing markets), coordinated by ACER which was suggested to get more regulatory oversight responsibilities additional to its powers as currently envisaged.

Some countries have decided for underground cables (or 60/150 kV underground in exchange to citizens for more higher voltage transmission above the ground), which are up to ten times as expensive and need more expensive maintenance[48]. More distribution grid underground improves reliability and might be something to offer in exchange for citizens concerned about more overhead grids, but even then the overall length of transmission grids above the ground will increase considerably. Public concern will not easily diminish. In general, opposition against investments in specific locations tend to decrease when the inhabitants are not only confronted with what they perceive as negative aspects (such as space, visibility, health concerns), but also may reap benefits (co-ownership, rewards, being a frontrunner in clean technology).

The way forward could be as follows.

- Investments are regulated[49]. Nearly full decarbonisation of the power sector has to become a specific aspect of the output of grid operators, next to efficiency and quality[50]. Investment in transmission lines could be included in the regulated asset base (RAB, see Section 4.4).
- This will start with regional interconnection (France-Spain, Denmark-Germany etc). In the 2009 Third Energy Package national TSOs are obliged to draft a ten-year plan every year of infrastructure investments that are needed related to the proposals of market parties (EU Directive 2009-72). Regulators judge whether this draft corresponds with the needs of market parties and may force implementation. Regional TSOs have to draft a regional grid plan every two years. The new association of TSOs (ENTSO-E) will combine these plans into a two-yearly European infrastructure plan. Altough the EU-wide plan is supposed to include a European view on the networks and generation adequacy, Regulation (EC) 714/2009 states that it shall be based on national plans, bot the other way around.
- These useful activities should be combined with a back-casting and more European exercise. It has been suggested in Chapter 4 to start this process by drafting zero-carbon fuel mix roadmaps by governments of neighbouring states (regions). It should be clear what the proposals of market parties imply. It has to be strived for to base the plans on binding outcomes of serious consultations. In the end this could become comparable with the 'open season' process in the gas market. The European Council could propose ENTSO-E to draft a long-term European infrastructure plan that corresponds with one or several scenarios to implement these roadmaps. In this way the question how to make the most cost-effective transmission infrastructure investments, cross-border and at national level, notably to accommodate more intermittent renewable energy, has been addressed right from the beginning. The specific tasks for infrastructure investment in the different scenarios are not exactly the same, but enough common ground has been found in the 60 or 80% RE scenarios in the Volume 1 analysis to decide upon specific additional projects.

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48 In the ECF model 20% of additional transmission is underground. If this would be 50% overall costs of grid expansion increase with 60%.

49 The possibility of merchant lines exists in Europe as well. For example, the Britned line between the UK and the Netherlands has been constructed as a merchant line due to the fact that the two NRAs involved could not agree on how to regulate the investment. There are low expectations of the additional investment in transmission to be invested as a merchant line.

50 For example, ENTSO-Es current main objective is to promote the reliable operation, optimal management and sound technical evolution of the European transmission system in order to ensure security of supply and to meet the needs of the Internal Market. The promotion of a nearly full decarbonisation by means of investments in and operation of the transmission system could be added.

Equally important is that the relation between transmission operators and generation has to change. In a situation of huge investments in transmission, the relation between generation and transmission (in which nowadays transmission has to follow generation in a passive way) has to become more balanced. The situation of passivity of grids has to end and a more active intra-regional and eventually European approach is needed[51]. This could be done in three ways:

a. At this moment the national regulatory authorities (NRAs) are responsible for regulation of interconnector investments. They basically have a national focus, which does not stimulate a European approach in transmission investment. Increasingly more concrete and important actions for border-crossing are found in the EU Regulations. However, they are still under control of the member states due to the time consuming and complicated Comitology process. The principal task of ACER could be to "promote the development of a European zero carbon and reliable energy infrastructure". In this respect, ACER could be enabled to intervene, mediate and perhaps even overrule the decisions of NRAs if the wider sustainability and security interests of the EU power market are at stake. This would imply the following (cf. de Jong et al, 2009):
   - Since the TSOs cannot be forced to invest in loss-making projects (including storage and buffering), ACER could have a role in convincing NRAs to recover investments at reasonable return rates.
   - ACER could play a more pronounced role in licensing and permitting new transmission infrastructure, by underlying and arguing the European significance of a (possibly cross-border) project. As the TSOs are supposed to make proposals based upon infrastructure plans, ACER could check whether a transparent process of stakeholders' involvement has taken place. This is somewhat comparable to FERC's role in the US interstate gas market, which has led to a high sustained level of interstate investments in pipelines.
   - ACER could monitor the role of energy exchanges in the management of cross-border interconnectors.
   - ACER could be organised and financed in such a way that it will become the final decision making authority for the EU Network Codes.

b. At this moment Europe does not have much experience with locational pricing (as the US has). The European ideal is still a 'copper plate'. This was not a big problem as long as congestion costs were low. However, this will change. The Volume 1 analysis showed that in an optimized model 103 - 166 GW of additional transmission capacity is needed in the 60% and 80% RE pathways without additional demand response (as said, only modelled as transmission between nine European regions), but in a copper plate model it could have been up to seven times as much. This is unaffordable. Some countries already have different prices in regional zones, and others are considering them, but compared with nodal or locational marginal pricing systems ('LMP') in the US the European zonal transmission charging systems are unsophisticated. Improvements would provide strong incentives to build infrastructure in those trajectories where it is really needed, and to reduce marginal energy losses. Without locational pricing generators are not stimulated to invest in places where this is most efficient. The massive deployment of renewable energy will need a re-balancing of costs of related infrastructure, which also could be paid by generators (which can be included in the subsidy systems, but has to stimulate efficient use of infrastructure), who could perhaps use nodal or LMP pricing arrangements. European regulation already enables taking such a step. The effect cannot be to discriminate against renewable energy, but a balanced approach could be searched for in which the relative position of renewable energy on average does not deteriorate, but overall the distance between generation and consumption is stimulated to be as low as possible. A better utilisation of infrastructure might be rewarding for all involved.

[51] This will lead to a more 'active' infrastructure. Actually, this terminology has different meanings. In our proposal it means a more interactive approach with regard to planning and investments. In the literature, the word 'active' is used to differentiate between a passive and active distribution grid; the active one is the smart grid with a coordinated centralized and distributed control of generation. Comp. Woodman and Baker, 2008 and paragraph 5.6

c. TSOs remain obliged to connect generators to the grid, but a decision on the location at least of larger plants could to a larger extent be taken in an interactive process. This is exactly the idea of the infrastructure plans. In this way costs can be saved.

In this way, Europe will gradually move to elements of regional planning on generation adequacy (see Chapter 4) and transmission investments. Infrastructure planning is already stronger than 'indicative' as in the end the government decides on the spatial opportunities which influence investment decisions to a large extent. The more precise the government may articulate its preferences, the larger the impact might be. Generation planning will remain to have a strong indicative aspect, as market parties decide whether to invest or not, but spatial aspects, permits, other aspects like regulation of storage (CO_2, nuclear waste, but also gas storage) will influence these decisions to a large extent. At the same time short run efficient scarcity and locational pricing will be ensured by day-ahead, intraday and real time nodal pricing. Regional market couplings and coordination of power exchanges and wholesale markets are a bottom-up approach towards European markets closer to pools models (combined with long-term contracts). ACER could move from conflict solving and giving advice towards organising a transparent process of all cross-border transmission lines.

5.4 Balancing and storage

The Volume 1 analysis has shown to what extent more intermittent power will lead to balancing challenges. These are created by the limited predictability and the high fluctuations in production levels of especially wind and solar PV generation, as these energy sources are not controllable and fluctuate relatively randomly. Generators may invest in flexible and fast responding peak capacity. However, to some extent the use of storage may in the future be more efficient than the deployment of more balancing power. For example, Spain recently developed 3 GW of additional hydro pumped storage capacity (ENTSO-E, 2010). Furthermore, and in several respects more efficient, energy suppliers may develop demand side response actions in junction with electricity consumers. Volume 1 computed that 20% demand response might reduce the need of additional grid investments by 15-25% and investments in additional back-up capacity by 30-40% and reduces the need to curtail renewable energy when demand is low. Demand response has been looked at in Chapter 4, and the importance of consolidating adjoined control areas has been mentioned in the preceding section. In this section balancing and storage issues will be investigated.

Volume 1 analysis shows that even without additional demand response the level of renewable energy curtailment may remain small.

Table 5.1 *Required reserve capacity in different scenarios (w/o additional demand response), 2050*

	Response capacity (fast response from seconds to 15 min.)	Reserve capacity (for 4 hrs - day)	RE curtailment [%]
Baseline	9 GW	22 GW	0
60% renewable energy	29 GW	123 GW	2
80% renewable energy	43 GW*	183 GW	3

* The IEA, looking at storage options for short term intermittency problems in a low-carbon European power system, computed with variation levels between 5 and 30% storage capacity, ranging from 0 to 90 GW in 2050. The average therefore is exactly the same as in the 80% RE scenario (IEA, 2009).
Source: Volume 1 analysis.

Response capacity is assumed not to be shared between the regions, due to the speed of necessary interventions (a conservative assumption), but in reserve capacity a shared response is an extremely cost-effective approach. Inter-regional transmission capacity provides significant balancing: overlaying intra-day and inter-seasonal demand curves and intermittent generation curves. Wind energy in the Northwest and solar in the South are negatively correlated. In the 60% and 80% pathways reserve sharing between the nine regions reduces total reserve requirements by 40% (Volume 1 analysis).

Different storage alternatives are available[52]. They have to be looked at with regard to the volume of storage (ranging from 1 MW or smaller to 1 GW or larger) and the speed and continuity of storage (from minutes to months). For our case large and potentially continuous storage options are most relevant. Examples of such storage types are Compressed Air Energy Storages (CAES) and Advanced Adiabatic Compressed Air Energy Storage (AA-CAES). At this moment efficiencies of 50% are attained, but research and demonstrations are underway aiming at more than 70% efficiency. Pumped storage is a well-known way to store electricity, but the easy available potential has been used. Subsurface pumped storage might be possible but is expensive. Hydrogen is also a potential way to store electricity. Another option is to produce power by way of an IGCC in which production of hydrogen is an alternative for power at times of low power demand (Oeko-Institut - Prognos, 2009).

Box 5.3 *Cost benefit analysis of storage options in the Netherlands*

ECN tried to make a cost/benefit analysis of additional energy storage options in a 'real energy transition' scenario (coal with CCS, high electricity and CO_2 prices, high share of wind energy) in the Netherlands in 2020. The scenario is not fully compatible with the ECF policy Pathways, but is largely comparable And the outcome is still relevant:

- Storage options considered were CAES, an 'energy island' in the North Sea, underground pumped accumulation (OPAC) and an additional high voltage cable to Norway to make use of the hydro capacity.
- CAES scores relatively well and has a positive value from the point of view of society; both investment and environmental costs are relatively low.
- A second NorNed cable from the Netherlands to Norway scores good as well due to a second ranking in investment costs and relatively low O&M costs (this is the type of transmission that has been modelled by ECF).
- These two alternatives would be preferred.
- An 'energy island' and underground pump accumulation are relatively more expensive but could still be defendable from a social point of view in several variants of the transition scenario. In other variants the cost substantially surpassed the benefits.

Source: Dutch Ministry of Economic Affairs, 2008a.

It is to be expected that both response and reserve capacity, including storage options with comparable volumes and speed, will remain regulated activities of the TSOs. Longer-term options, especially storage, will have a value in the power market as prices will reflect scarcity. That makes sense additionally because in this way cost-effective choices between either long-term storage investments or very flexible power generation like OCGT will be searched for.

5.5 Distribution

At the level of distribution grids, three approaches that eventually will merge into the smart grid concept may be observed. Smart meters, distributed generators and flexible demand options like electric vehicles and heat pumps are parts of the transformation of distribution networks into smart grids. Heat pumps will be looked at in the next box, EVs in Chapter 7, and smart meters and especially distributed generation and smart grids will be investigated more closely in this section as they raise related policy and regulation issues. The combination of smart meters,

[52] Storage has not been modelled in the ECF pathways.

smart grids and distributed generation will lead to a paradigm shift in the way distribution grids - and finally also transmission - operate.

Box 5.4 *Heat pumps as a storage option*

A heat pump is a machine that moves heat from one location to another using mechanical work. Common examples are refrigerators. Heat pump technology has developed well recently and heat pumps are increasingly used for cooling and/or heating of dwellings or offices. They enable further electrification of heating; an additional advantage is the high efficiency of electricity use. Important with respect to the use as an energy storage and balancing option is that in principle heat pumps could be used in an interruptible way, somewhat comparable with air conditioning. Experiments in Denmark and Finland have shown that this is possible. Electricity demand by electric boilers and heat pumps halved the number of hours with a price equal to zero in a recent February month and increased revenues to generators with 2 to 2.6%. In the city of Copenhagen a favourable business case certainly could be developed. However, heat pumps will definitely need specific contracts or control, as without such arrangements they could easily *increase* the peak load instead of *diminishing* it. It is understandable that grid operators are in favour of active interaction with local governments to find overall efficient solutions: an example of 'active' infrastructure investment.

Currently, heat pumps are mainly used in new family houses in countries like Sweden, France, Finland and Germany in which a mass market is developing. Heat pumps are more energy efficient than gas-fired boilers, in average situations currently some 30%. They arre increasingly efficient. The heat pump market for renovation is underdeveloped except in Sweden and Switzerland. The IEA has a Heat pump programme of which Annex 30 states that "it is clear that in many cases heat pumps already can, or will soon, be used as a preferable retrofit choice". It is assumed in the Volume 1 analysis that not only new buildings, but eventually 90% of the existing fossil fuel heating (mostly natural gas) will switch to electric heat pumps. Due to space constraints in metropolitan areas, it is assumed that larger heat pump systems will dominate the cities instead of single building systems.

Stringent building standards for existing buildings are needed for deployment (see Chapter 6).Volume 1 assumes that 90% of the remaining demand in buildings after efficiency is covered by decarbonised electricity. Furthermore, the question whether heat pumps are considered a renewable option according to the European definition is still pending. The combination of zero carbon power and heat pumps is a strong one. In the Volume 1 modelling *more than half* of the emission reduction for heating is due to the deployment of heat pumps.

Source: IEA (2008c).

Smart meters are already included in the European Union's Third Energy Package of 2009 envisaging that, subject to the assessment of costs and benefits, member states shall ensure the implementation of intelligent metering systems. Several European countries (Italy, Denmark, Finland, Sweden) are making good progress in introducing smart meters, sometimes explicitly related to compensating wind intermittency (Denmark, Ireland, Spain)[53]. Standardisation is essential. Smart meters enable utilities to improve demand response by varying prices during the day and by offering contracts enabling consumers to level off peaks and troughs. It is therefore preferable to value smart meters as a specific part of the infrastructure (instead of the object of individual choice). In this way the market becomes smarter, but grids still don't change. Eventually, with increasing intermittent renewable energy, EVs and electric heat pumps will not be enough and (the use of) infrastructure itself has to be optimised. That is the end of the copper plate in the distribution grid and the beginning of the smart grid.

[53] Obstacles have emerged as well. In the Netherlands privacy aspects played an important role and Parliament did not allow an obligation for all users to install a smart meter. In Germany it has been computed that the cost increase due to the more expensive meter is considerable: consumption has to decline with at least 19% to make the investment profitable. Consumers wanted to use the smart meter to get more information and were not in favour of automatically switching off and on of appliances. See Sauthoff and Graf (2009)

Distributed generation (DG) consists of facilities that provide active power whilst connected to the distribution system and with a rated capacity generally lower than 50 MW (Cossent et al, 2009). The share of DG in total electricity output is more than 45% in Denmark, between 15 and 20% in Germany, the Netherlands, Spain and Sweden, between 10 and 15% in Austria and Portugal and less than 10% in other member states. The increased share of DG such as wind turbines and solar-PV can create problems for distribution networks in terms of stability, power quality and network congestion. As long as DG penetration is limited, connection of DG units to the grid will not cause many problems. But the grids have to be prepared to connect larger shares (Van Werven et al, 2006).

"A smart grid is an electricity network that can cost efficiently integrate the behaviour and actions of all users connected to it - generators, customers and those that do both - in order to ensure an economically efficient, sustainable power system with low losses and high levels of quality and security of supply and safety" (ERGEG, 2009). A smart grid consists of a number of features:

- Optimising grid operation and usage - this concerns decentralised grid operation and market based treatment of electric power flows.
- Optimising grid infrastructure concerns building new and optimising the existing grid facilities.
- Integrating large-scale intermittent generation.
- Information and communication technology concerns ICT tasks and standards.
- Active distribution grids concerns 'activating' the grids comparable with the operation as is the case today with TSOs (and beyond).
- New market places, users and energy efficiency include mainly demand side options like EV and heat pumps and puts the customer in focus.

The smart grids enable a transformation from the actual relationships of distribution networks, customers and generators. It will allow distributed generation (DG) to participate in balancing and reserve markets and to positively contribute to the operation of the network through voltage support. The increasing electrification of transport and heat will modify the energy demands of customers. In short, it will transform a distribution network from a 'one way' into a 'two way' system.

Most important regulatory issues with regard to distribution companies enabling them to introduce smart grids are the following (cf. Cossent et al, 2009):

- *Economic signals.* Which connection charges have to be asked for: shallow or deep? Under shallow charges, the DG pays only the direct costs of connection. Under deep charges all the costs of connection, including upstream network reinforcements, are asked for. In the short run, both in theory and in practice, shallow charges are preferred. In theory, as deep charges are extremely difficult to compute[54] and in practice, as the majority of EU member states have implemented them. At the same time, it makes sense to allow for user of service (UoS) charges to be paid by DG and users like heat pumps and EVs as a means to send DG operators and users efficient economic signals. Efficient UoS charges might include differentiation per location and time of use. This cost causality criterion implies that they can be either positive or negative (when generators or these users do not pay the charges, other consumers have to pay them). Several approaches are feasible to encourage smart grids in an economically efficient way: bilateral contracts between distribution network companies and DG, regulated payments or acknowledgement in UoS charges. The optimal approach differs from case to case, also depending on national regulatory frameworks.
- *Regulation* of investment costs of the distribution companies. Gradually, an increased share of DG, heat pumps and EVs will lead to additional costs for DSOs; in the case of DG espe-

[54] Eventually, when shares of DG will have increased considerably, deep charges could be more efficient (Vogel, 2009).

cially when it surpasses 20% (De Joode et al, 2009). Understandably, currently very few countries explicitly consider DG, heat pumps or EVs as a cost driver. An additional incentive based regulation is needed, both for CAPEX and OPEX. The recovery of CAPEX is especially important where shallow charges are paid. Due to increased costs for higher shares of DG, heat pumps or EVs, some kind of 'over compensation' in CAPEX and OPEX regulation has been suggested (de Joode et al, 2009).
- *Innovation.* To attain smart grids additional investments in the quality of the distribution grids are necessary. Some EU member states, like the UK, have already considered how to do this. The UK regulator Ofgem has allowed for a specific tariff uplift of 0.5% for innovation, for a Distribution Generation Incentive to connect more DG and for Regional Power Zones to do this in a more strategic way. Up to now, this regulatory approach has not been extremely successful (Woodman and Baker, 2008), but more recently the level of investment is slowly increasing. Specific incentives for innovation are necessary to achieve a long-term transformation of distribution networks in which both customers, DG and the DSO are able to play an active role. This requires a longer period than the regulatory RPI - X one. The European regulators also agree that "A major challenge for regulators is to find ways of encouraging an adequate level and scope for more radical innovations while providing an appropriate degree of protection of consumer interest" (ERGEG, 2009).

In this way the approach is moving from connection via integration and innovation to a full transformation of the system. It is to be expected that pilots will play an essential role in this transformation (comparable with the demonstration activities with regard to EVs). An interesting approach - among others - is the Dutch Innovation Programme Intelligent Networks, including:
- Pilot projects.
- With the aim of learning by and teaching to consumers, producers, grid operators and commercial parties about their roles.
- And in this way preparing stakeholders for a large-scale rollout of the smart grids based upon a shared vision and a coordinated approach of all different innovation activities.

The paradigm shift of the distribution network has three layers:
- The institutional structure: grid operators become distribution system operators comparable with TSOs; consumers may start to produce as well; new services and new types of contracts will be offered.
- Regulators have to allow for additional investment costs.
- The market model. New business cases are needed for the grid operators, utility companies and those market parties involved in the rollout of EVs.[55]
- Applications and grids: the physical and ICT part of the system. Grids physically will enable a two-way electricity flow.

In the Dutch approach the period 2010-15 is needed for the pilots and actual implementation can start consequently (Energietransitie, 2009). The pilot projects can vary in the role of the consumers, grid operators (in different degrees of activity) and new market parties (aggregators, virtual power plants, etc.). These variants will ask for different regulatory rules, tariffs and ICT structures. A lot of learning is needed before the most effective and efficient solutions will have been found. Learning experiences to some extent are being shared at the EU level (e.g. the Smart Grid European Technology Platform as part of the SET process, cf. Chapter 3).

We have to realise that distributed generation (DG) will be connected to a network level that was not designed for that purpose. Denmark is showing that it is possible. It has implemented and tested new network concepts. With new 'cell concepts' it is shifting more responsibility for

[55] An interesting example is the European FENIX project which looks at case studies in several countries offering significant (potential, financial) benefits to all stakeholders involved. Main impediments turned out to be regulatory barriers.

network control to the Distribution System Operators to balance generation and demand locally as far as possible (Bauknecht and Brunekreeft, 2008). In this way a new relation between the TSO and DSOs will be searched for. The main role of the TSO will become to balance power flows including those produced on distribution networks and to transport energy from remotely connected renewable generation.

Eventually that will be very cost-effective. The ‘passive’ distribution network is dimensioned on peak generation capacity of the DG. When DG enters the distribution network, upgrade investments based on peak DG output are undertaken and for the remainder any electricity production from the unit is taken as given. The active network management philosophy is based upon the smart grid. Both consumers and DG load and generation characteristics are taken into account in network operations and planning. Again, this is an issue in which locational pricing has to be explored. Locational pricing is well understood in the context of transmission, but the context of distribution might be just as important (Van Werven et al, 2006).

The issue of taking next steps in RPI-X regulation has been dealt with. Current regulation is mainly interested in cost efficiency. This has been extremely useful in the past, but in the future investments are just as important. The current regulation stimulates especially DSOs to do the same things more efficiently, but it does not really give incentives to look for better alternatives. Due to price-cap regulation and a short regulatory period (3 or 5 years), long-term strategies are discouraged. This has to change. Regulation has to find a new balance between operating cost efficiency and investments. In other words the regulator has a crucial role in ensuring sufficient network investment while keeping price rises down via appropriate incentives. This will lead to a new role for the regulator that in a more general sense has been called ‘constructive engagement’. This will include ‘negotiated settlements’ between buyers and sellers of network services (Pollitt and Bialek 2008), which is the regulatory rephrasing of a more active role of infrastructure.

Finally, one has to realise that this includes “winning the hearts and minds of consumers” to realizing all of the benefits that a smart grid will be able to offer (ERGEG, 2009). End-user participation of consumers is paramount in increasing energy efficiency and demand response. The activity of the consumer may be small (e.g. by taking a cheaper contract that allows the operator to manage within the bounds of demand) or large (e.g. by managing appliances in such a way that the price of consumption is lowest). The possibilities for activity are largely dependent on the functionalities of the metering system. Eventually, users will not only be able to participate as consumers but also as producers. More active participation becomes essential when electric vehicles and electric heat pumps will further diffuse. Volume 1 analysis shows for example that smart charging of EVs leads to a 25% reduction in peak load.

5.6 Conclusions

Box 5.5 *A new role for the government?*

Recently, the need for a market reform was also voiced by the UK Energy and Climate Change Secretary Miliband (*Times* on line, February 1, 2010; cf. Box 4.4). This is related to three issues that have been mentioned in Chapter 3:

- What will be the role of renewable energy when the specific incentives will have ended.
- How will CCS further develop after the demonstrations.
- Is nuclear feasible without some kind of assistance?

As long as risks are perceived to be too large, companies will not invest in these technologies. These risks will not disappear. Skillings (2010) argues a clear ‘narrative’ is needed. He distinguishes three options: market driven and technology neutral; resource planning by governments for key options; keeping all options open. Skillings posits that all options are defendable, but that it is essential for governments to make a choice as otherwise companies will not be able to contribute to a clean technology future because risks remain too high. Other authors are more explicit: "It is difficult to see how governments will be able to meet their own emission commitments and targets without taking a strongly active or 'interventionist' role" (Scrase and Mackerron, 2009).

These are urgent issues and a clear narrative will certainly help the political debate and could be of decisive importance. However, it could be argued that in the end the risks have to be diminished by *a combination* of the three options. The essence of the narrative that is needed, we believe, is that governments have to be explicit about the role they envisage and that these roles have to be consistent. In the end the precise view will differ in the United Kingdom or France, Germany or the Czech Republic.

1. Governments already make choices in their technology policies, as has been argued in Chapter 3. As long as this is necessary - and this will be the case for at least the next 10 to 15 years - renewable energy and CCS could be strongly supported by financial instruments.
2. It has been argued in Chapter 4 that it will be useful and maybe essential for governments - interactively, with all relevant stakeholders and gradually not only at national levels but also at the levels of neighbouring countries in Regional Markets platforms - to develop 'roadmaps' of the fuel mix they prefer. The ECF pathways could be a stimulus for the debate needed to develop these roadmaps.
3. Gradually, as the cost differential between clean technologies and fossil fuel decreases, financial support is less needed. However, governments will continue to use technology specific instruments to influence the realisation of these roadmaps. Without a solution for high level nuclear waste it is difficult to envisage how a fleet of nuclear plants will be built; without a clear and transparent spatial policy no wind turbine park can be established; and without spatial planning no CCS activity is possible. Only public-private partnerships are able to realise these roadmaps.
4. A carbon cap and price will support the realisation of the ultimate target (Chapter 2). If carbon prices remain too volatile to be reliable indicators for long-term investment, financial instruments and specific regulation could reduce private risks.
5. However, in our view the market will remain the best mechanism to allocate risks between private investors, governments and consumers. Without a market mechanism eventually the consumer will pay more than necessary, both with regard to energy investments and utilization (compare the availability factor of nuclear plants in the early 1990s with the current one).
6. Due to the changed cost structure of power generation a new approach is needed in this market (Chapter 4). Either the actual market design has to be improved (more scope for long-term contracts, up to 15 years or more, and policy approaches to stimulate demand-side response) or new designs have to be developed (capacity mechanisms). Without adaptations of the market design it is difficult to envisage how large investments in capital intensive generation will continue to be made.
7. Infrastructure will play an essential role (Chapter 5). This is quite normal in network industries. Nobody doubts that governments decide on the planning and realisation of motorways and railways. Although the legal situation is different, in essence the electricity infrastructure is comparable. In almost all European countries regulated companies will commission these investments; often realisation takes place in monopoly networks, but by means of tendering (other) private companies could play a role in the actual realisation. A more active role of the infrastructure might be the end of the 'passive' role it nowadays has. The 'roadmaps' as sketched above could be a starting point of infrastructure development. However, infrastructure planning has to remain flexible enough to facilitate both intra- and inter-regional transmission and 'smart grids' in distribution networks. It is not a question of either/or - both are needed.

In this way an active government might use a range of policy instruments that combine flexibility and stability, national and international approaches, and elements of markets and planning. Time is ripe to start a debate on whether this is the right approach.

Europe has to be prepared for a huge wave in investments in transmission and distribution. In this Chapter the following proposals have been made.

- As infrastructure is becoming more important, the situation in which it is only allowed to be a ‘passive’ partner in the power system has to finish. Infrastructure will get a more active and leading role. Locational pricing in both transmission and distribution grids stimulate cost effective siting of generation and could be promoted. The European Commission could propose ENTSO-E to draft an European Infrastructure Plan that corresponds with the roadmaps of the energy system that has been proposed in the preceding sections, to be drafted by governments at the level of the Regional Markets in close cooperation with relevant stakeholders and to be based on one or several zero-carbon scenarios such as those of ECF. This backcasting approach can build upon the approach that has been included in the 2009 Third Energy Package in which regional TSOs have to draft regional grid plans every two years, which are combined by ENTSO-E into a two-yearly European Infrastructure Plan.
- Grids could explicitly get the task to facilitate a zero carbon energy system with equal priority to cost effectiveness and supply security. The principal task of ACER (the agency of energy regulators) could become to “promote the development of a reliable and nearly zero carbon energy infrastructure” in Europe. It could have a role in convincing national regulatory authorities to allow necessary investments and, more generally, it could play an active role in enabling a European sustainable transmission grid. Its planning mandate could expand beyond the existing one to make a long-term approach feasible. ACER could support a transparent process by the regional TSOs in which they demonstrate how customers and producers are committed to use new grids for a longer period.
- In this way more funding becomes available. Further additional funds could be searched for, such as the Structural and Cohesion Fund and additional funding of the SET Plan for smart grids. As part of the overall review of the EU budget allocation of funds to energy infrastructure could be considered. Communication with all stakeholders should search for local benefits as in the end local stakeholders will only accept new investments if they also perceive a benefit.
- Balancing becomes more important and will remain a responsibility of regulated grid operators. However, grid operators must become more regional in scope and authority, since it will be impossible to deliver reliable operation in any of the decarbonised pathways based on the currently envisioned population of autonomous grid operators. Storage may use price differentials, and investment in storage has market opportunities.
- Regulation of distribution networks must facilitate the rollout of smart meters, the development of distributed generation and smart grids, probably even by some kind of overcompensation and incentives for innovation. Economic signals remain important. Pilots and joint learning are the way forward. Funding and guidance for a coordinated programme of pilot projects to demonstrate technologies and operative practices in both member states and at the EU level are crucial.
- More generally, a combination of ‘top-down’ (from Europe to the regions and nations) and ‘bottom-up’ (from the nations and regions to Europe) approaches is needed. Some top-down guidance remains necessary as the ultimate aim is one European infrastructure. But, as the experience with regional markets has showed, most progress will be made by experiments. The North Sea could be an interesting example of establishing a Regional Transmission Operator.

6. More energy efficiently urgently needed

6.1 Introduction

At the Spring Council 2007, the EU Heads of States and Governments committed themselves to increasing energy efficiency in the EU with 20% compared with a Business as Usual scenario[56]. The EU is far from reaching this target. Even when including the measures that are still in the pipeline, only 11% consumption reduction will be achieved in 2020 (EU Commission 2009, draft paper).

Energy efficiency is probably the most rewarding and most difficult part of energy policy. Rewarding, as it is the only policy objective that has the potential to be immediately beneficial to all aspects of energy policy: affordability, sustainability and security. Without strong energy efficiency policies the *Roadmap 2050* objectives will not be met. The contribution to the reduction of CO_2 emissions as envisaged by 2050 in any credible sustainable energy scenario is some 30-40% of the total reduction, which is the most important single factor (IEA 2008). Efficiency improves security and most efficiency improvement measures have a short pay-back time. But it is also difficult, as efficiency measures are relatively invisible, consist of a combination of smaller activities, need both bottom-up (many investors) and top-down (policy) approaches and finally lack strong lobby groups encouraging governments to take next steps. Therefore, a huge gap may be observed between the potential to increase efficiency and actual implementation of policies.

At the OECD level, annual improvement of energy efficiency fell from 2% in 1973-90 to 1% in 1990-2006 (IEA 2009c), although the rate of efficiency improvement may have started to improve slightly in the last few years. Within the family of OECD countries the EU lost some of its previous shine, especially in implementation. Compared with other countries, the EU does not lack in ideas but in implementation. A recent IEA study (IEA 2009c) showed that many possible activities promoting energy efficiency are being 'planned' in EU countries, whereas in other OECD countries like Japan or Korea they have been implemented already. In most cases some EU countries were already 'best in class', but other ones are clearly underperforming.

To attain the *Roadmap 2050* ambitions, a strong increase in efficiency is needed. This Chapter does not analyse all aspects of energy efficiency in-depth, but looks only at the most pressing issues that may be improved in Europe. In section 6.2 the increase that is needed in the next two decades will be estimated. Next, some considerations for additional policies will be given. Completely new approaches are less needed, but more has to be done and much more can be learned from each other. This will be illustrated in policy approaches in the buildings sector. The last section will summarise the conclusions that are drawn.

6.2 The target

To go forward, one has to ensure that the 2020 efficiency target will be met. Unfortunately, at this moment the EU has a rather complicated way of computing this target. The 20% target is not related to efficiency improvement, but it is related to the 'PRIMES 2007 baseline'. Therefore, the actual target is *higher* than 20% as some efficiency improvements are included already in the baseline, e.g. autonomous improvements of appliances. It will always remain difficult to decide which activities are already included in the baseline and which are not (Schule, 2009).

[56] ECN understands this as primary energy efficiency improvement. All ambitions and figures in this chapter are formulated in primary energy.

The indicative Energy Services Directive requires member states to attain 9% final energy savings of energy use that is not part of the ETS in the period 2008-2016, which means: households, most service sectors and small industry, transport. The directive regards energy savings beyond the autonomous savings, to be realized with policy measures from 1995 and in some cases earlier. Only by estimating how much efficiency improvement might take place in the ETS sectors the 2016 target can be related with the 2020 target. This illustrates how difficult actual measurement is.

It would be easier to define energy efficiency in a somewhat less fragmented way. It will not be suggested that the European Commission should change its definitions, but the approach of the IEA indicators will be followed (IEA 2009e), to get an impression how much has to be done in comparison with what has been achieved in the past.

In Table 6.1 the relevant energy figures as computed by the IEA for the recent two decades and estimated by ECF for the next two decades in the ECF *Roadmap 2050* policy scenario are presented. The difference between GDP and energy demand is the annual change in energy intensity, an indicator that is presented in many statistical overviews. Energy intensity, however, consists of two completely different factors: the structural change of the economy (more banks, less steel factories) and the increase in energy efficiency. These factors are known for the period 1990-2007. ECF has assumed that the structural change in the economy will increase. This is an important aspect one has to take into account as no clear policies are available to 'guide' this structural change. In the ECF Baseline scenario the annual energy intensity improvement in 2010-2030 would have been 1.3%. If one assumes that the structural change in that scenario would have been comparable with the past (0.5%), this would have implied a small decrease of efficiency improvement. The difference between annual energy efficiency improvement in the baseline (0.8%) and policy scenario (1.6%) is impressive and demonstrates the task ahead.

Table 6.1 *Realisation and estimate of needed energy efficiency (annual change in %)*

		1990-2007	2010-2030
GDP		2.2	2.0
Energy demand		0.7	-0.5
Energy intensity		1.5	2.5
of which:	structural change	0.5	0.9
	efficiency	1	1.6

Source: IEA (2009g), ECF and ECN analysis.

An efficiency increase from 1 to 1.6% annually might seem small, but one additional factor has to be taken into account: the autonomous improvement of efficiency (a new appliance is more efficient than the old one, even without energy policy). In the past decade this has been 0.7% annually, which either will remain the same but due to more emphasis on new clean technologies worldwide and with consistently higher global energy prices it could increase to some 0.8-0.9% as well. Therefore, the effect of energy efficiency policies has to increase from (1-0.7=0.3% annually) to (1.6-0.7/0.9 = 0.8% annually). The effect of energy efficiency policies has to *increase two to threefold*[57]. This is an impressive task.

57 A draft study for ECF and RAP by Ecofys and Fraunhofer concludes in a comparable way (*The Feasibility of Binding Energy Savings Targets in the EU*, draft March 2010). Boonekamp (2006) estimates that the 20% efficiency target of the 2005 Green paper implies a yearly efficiency improvement of 2.5% in 2005-20 (0.7% autonomous plus 0.3% baseline + 1.5% additional policies). The Dutch government has an official target to realise 2% efficiency improvement annually. This implies that our estimate may be on the low side.

6.3 Policy instruments: why are they needed

Before searching for solutions, one has to look at the causes. Why does such a large discrepancy exist between dozens of studies showing huge opportunities for cost effective efficiency improvements and the apparent resistance of consumers and companies to act? Basically, this has two causes (Nassen et al., 2008).

The first one consists of the large and well-known number of impediments. Barriers in companies to invest in energy efficiency are within the decision-making processes, lack of information, limited capital availability and lack of skilled personnel (Worrell and Price, 2001). In small companies the small size of energy efficiency projects and their difficulty in being bundled may be added. In households these impediments are partly the same, but others could be added like the landlord-tenant problem (one has to invest, the other one gains). These split-incentives may result in the consumer's insulation from the price signal. This implies that policy measures have to tackle especially these causes. E.g. only increasing energy or CO_2 taxes does not solve them in cases tenants have to pay rents including energy costs. When efficiency measures in buildings offer significant negative costs but need huge upfront investments that cannot be financed, the financing has to be looked at. Voluntary agreements will not always be effective by themselves but might motivate decision-makers as a part of a larger package.

This leads to the second reason, which is a more psychological one. When people are simply not interested in an issue and consider other things to be more important they cannot be easily stired into action. For many people saving energy has a low priority. They either have to be forced (regulation) or it has to be made very attractive. In economic terminology several of these reasons are summarised in high 'transaction or hidden costs'. These hidden costs are real and lead to an overestimation of the net effect of efficiency programmes. They also ignore the 'hidden benefits' in terms of non-energy issues (e.g. noise reduction by insulation) (Sorrell 2009). Therefore Steg (2010) pleads for a combination of 'psychological strategies' (changing people's knowledge or motivation) embedded in 'structural strategies' (changing the context in which decisions are made so as to make energy conservation more attractive).

Policy measures have to take these reasons into account.

Policy analysts agree that effective energy efficiency policies consist of *packages*. Single instruments do not suffice. This again has two reasons. First, one has to remind the statement of a former colleague in a European ministry that 'policy measures are either ineffective or politically unfeasible'. This is exactly the reason that carefully packages have to combine sticks and carrots and that sticks mostly will be introduced gradually. But another reason is that it is the package as a whole that improves the effectiveness of the different elements that need each other. A strong standard may lead to postponement of investments when people don't know what can be done or when builders are not able to construct the efficient solution. And people will act quicker when alternatives are not only available but very easy to attain. In general policy packages of regulation combined with enabling environments, while simultaneously training staff and providing more information to customers have proven to be most successful (IEA 2009e).

6.4 The current situation in the European Union

This is exactly what has happened in the EU. To analyse EU policies one has to differentiate between the ETS and non-ETS sectors. If the improvement of ETS will be implemented as proposed in Chapter 2, large companies and power producers will have an effective incentive to improve efficiency as well. Therefore ambitious regulatory instruments for ETS sectors seem to be neither effective nor efficient, as a large CO_2 reduction already will be imposed. Chapter 3 has suggested that gradually emission rights could be fully auctioned for industrial companies, as will be the case for power generation. In practice, many tax exemptions exist for energy intensive industries which are understandable from a competitive point of view but do not incentivise energy efficiency. A combination of careful steps in abolishing these exemptions with targeted long-term approaches to increase efficiency could be considered. Finally this could result in well-structured voluntary agreements (Worrell and Price, 2001). Finland, the Netherlands and other countries have good experience with such an approach. In the Netherlands this resulted in an ‘energy transition’ activity in which industrial sectors committed themselves to improving efficiency with 50% in a long-term perspective and are supported by public finance for innovation and demonstration activities (Van den Bergh and Bruinsma, 2008). In practice the voluntary agreements have been concluded with industrial branches of SMEs as well. Small enterprises are not easy to reach with efficiency policies, as the energy bill is only a small share of overall costs and energy efficiency has a low priority in daily management. To improve effectiveness, the Netherlands and Finland also formalised the voluntary agreements: SMEs are helped to achieve considerable efficiency gains (say 20% in 8 years) in exchange for support and help, simplified procedures for environmental regulation compliance and sometimes tax rebates.

Current policies in the non-ETS sectors are framed in the Energy Efficiency Action Plan (EEAP) of the Commission, that was adopted in 2007 (Annex 1 of the Presidency Conclusions 7224/07). The Action Plan has defined six priority areas (COM(2006)545):
- Dynamic energy performance requirements for products, buildings and services.
- Energy transformation.
- Transport.
- Financing, economic incentives and energy pricing.
- Energy-efficient and energy-saving behaviour of consumers.
- International partnerships.

The most important current instruments are the following.

A key aspect of the Directive on Energy End-Use Efficiency and Energy Services (ESD - 2006/32/EC) is the requirement for member states to prepare National Energy Efficiency Action Plans (NEEAPs). Member states have submitted their NEEAPs and demonstrated how they will reach an energy savings target (excl. ETS sectors) of 9% in 2016. A first evaluation of NEEAPs showed that it is unclear to what extent measures are additional - this is exactly the reason why a distinction between ‘business as usual’ and ‘additional’ policies has not been used in Table 6.1. Effective measures proposed in the NEEAPs are improving building standards, financing through specific funds (government, banks, companies), efficiency obligations or incentives for ESCOs (Schule, 2009). They will be dealt with in the next section. In 2011 member states will suggest new NEEAPs and this will offer new opportunities to further improve efficiency policies[58].

More specific is the twin approach to improve efficiency of equipment and appliances though:
- The establishment of minimum standards to improve the energy yield of 19 groups of products under the Eco-design of energy-using products Directive (2005/32/EC). Ecodesign is a framework directive. Every year minimum efficiency standards are formulated for groups of (mainly) appliances, like stand-by use, different types of lighting, televisions, computers, charging, electric motors, washing machines, fridges and freezers, boilers and water heaters. This is an effective approach.
- An appropriate, consumer-focused system to label and evaluate energy performance. The EU has a framework Directive (92/75/EC) and implementation directives for a limited set of

[58] CHP will not be dealt with in this chapter. It is uncertain to what extent CHP might play a role in the *Roadmap 2050* ambitions. On the one hand, a combination of power and heat production will remain useful in those cases in which CO_2 of the fossil fuel production might be captured and stored. This is possible in large scale facilities. In small scale facilities this will be extremely difficult. Therefore small scale CHP might be an interesting ‘bridging technology’ in e.g. existing buildings, but ultimately it will not play a decisive role in the 2050 pathways.

products. After more than a decade, the Commission is revising this directive to enlarge its scope to include other energy-using equipment and to upgrade labelling classification. This is a difficult debate, however, as different parties have different views on the way to achieve the upgrading.

A general issue for both the minimum standard and labelling is to rescale it automatically when new technological developments justify this. This would make a lot of unnecessary friction and debate redundant.

Buildings are targeted with the Energy Performance of Buildings Directive (EPBD) that has been in force since 2003 (2002/91/EC). After offering a general framework this directive formulates a requirement for minimum energy efficiencies for new buildings, for the refurbishment of large existing buildings (more than 1000 m^2), for energy certification of buildings when these are constructed, sold or rented, and inspection and assessment of heating and cooling installations. A significant challenge to the implementation has been its rate of transposition by member states.

In all, a framework of policy approaches has been introduced in Europe, next to instruments that already existed in the member states. The European Commission is in the process of evaluating and revising the Action Plan for Energy Efficiency. The general impression is that Europe is not sufficiently on track to meet the targets. Not all measures in the member states will be described, but possible next steps at a more general level will be analysed as the ambition has to increase considerably. First, types of approaches that are considered to be most effective and efficient will be looked at. Next, the most appropriate governance level of further improvements will be investigated.

A careful recent analysis of policy measures shows that several single policy instruments are both effective and cost efficient and therefore they could be the backbone of additional packages (Table 6.2).

Table.6.2 *Estimate of effectiveness and efficiency of policy instruments in non-ETS sectors and appropriate level of origin*

	Effectiveness	Efficiency	Appropriate level
Regulation			
Appliance standards	+	+	EU
Building codes	+	0	national
Procurement regulations	+	+/0	national
Energy efficiency obligations	+	+	national
Mandatory Labelling	+	+	EU
Mandatory audit programs	+	+	national
Economic			
ESCO support	+	+/0	national
Financial			
Tax exemptions	+	+	national
Subsidies/grants	+/0	from - to +	national
Voluntary			
Certification	+/0	+	EU/global

Source: Urge-Vorsatz et al, 2009.

In particular regulatory instruments are most effective and efficient, with high negative costs. This is an interesting outcome of these studies and different from more general economic analysis. The reason is that energy efficiency measures have to be taken by many single individuals, who are not aware of all relevant options and possibilities. Many market failures exist in this respect, but the knowledge deficit seems to be especially relevant (Persson, 2009). In most cases the national level is the most appropriate one, but with regard to appliances (Ecodesign) or cars this is the EU level; with regard to certification it might even be better to take this to the global level. Especially taxes are a useful complement to other efficiency improvement instruments (Boonekamp and Eichhammer, 2010) but by themselves they will not lead to the improvements that are needed. Assuming that the price elasticity will remain at the historic level, a 30% reduction of energy use due to efficiency increase would correspond to a three-fold increase of energy prices[59].

In effect, the EU and national approaches need each other. An interesting example offers a Dutch study investigating with which policy measures the national annual energy efficiency could be doubled from 1 to 2% (Daniels, 2006). The study assumed a stable regulation in the ETS sectors, It concluded that 43% of the effect of additional measures had to originate from Europe. Most important measures in the non-ETS sectors are mentioned in Table 6.3.

Table 6.3 *Most important single measures in non-ETS sectors to increase annual energy efficiency improvement from 1 to 2% in the Netherlands (2020 effect in PJ)*

		National	Europe
Services	Stricter standards for buildings	44	
	Stricter standards for appliances		53
Residential	Stricter standards for buildings	46	
	Stricter standards for appliances		79
Transport	Stricter standards for LDV		62
	More efficient driving and road-pricing	46	

Source: Daniels et al, 2006.

In a more general way it is interesting to note that the cooperation between the EU and its member states has led to a branch of studies on governance issues, in which the term ‘multi-level governance’ was coined. The definition of that term has since widened and is now understood as the “complex system of interactions between actors of all levels of government, engaged in the exercise of authority” (Jollands et al, 2009). This sounds theoretical, but is the heart of the observation that an effective *cooperation* of EU, member states and local governments is key to effective implementation of efficiency policies. In a recent study on this issue, Jollands et al (2009) drew the following conclusions:

- In most cases programme ownership transfers from top to bottom levels of governance. Initiated by the EU, nation states become owners, and initiated by national governments local authorities come to the fore. This is also the case with e.g. the Covenant of EU Mayors: initiated by the Commission, the Mayors now decide upon the programme’s further orientation.
- Many joint programmes are voluntary but to become effective they need formal decision-making processes. Of course, too much bureaucracy may lead to a lack of flexibility and therefore optimal levels of robustness have to be looked for.
- Accountability is important. Often, as time goes by, reporting systems receive less attention and in many cases there is a lack of ex post evaluation. This leads to a lower level of joint learning than would have been possible. For example, a key and very important goal of the Covenant of Mayors is to encourage cities to benchmark their energy performance against one another, but there is no obligation and it is unclear how this should be done. The same is the case with many voluntary agreements.

6.5 The buildings sector

Some 35 to 40% of EU energy demand stems from the buildings sector. In this section approaches, firstly, for new buildings and secondly, for the even more difficult issue of existing

[59] In the same way the study mentioned in Table 6.3 concluded that financial incentives in the residential sector did not have large effects, as the energy tax in the Netherlands is already quite high. However, this differs from country to country.

buildings will be looked at. These approaches are relevant for both commercial and residential buildings.

Almost all EU countries have standards for new buildings (four are considering them)[60]. Most EU countries have updated their energy efficiency requirements for new buildings in the past four years. Unfortunately, this does not automatically mean that new houses or offices are more efficient than old ones. The relative energy use in Norwegian buildings constructed before 1931 is lower than in those built after 1997 (Ryghang and Sorensen, 2009). The reason for this is that short term cost efficiency is considered to be more important than energy efficiency and actors have been aligned into a practice where well-known solutions are chosen and novelties avoided in order to keep construction costs as low as possible. But also in Norway there are signs of change: stricter regulations and a growing concern among architects to engage in sustainability. More generally, one may say that stricter regulation is a necessary condition for more efficiency but not a sufficient one. The levels of regulation vary substantially between member states. Looking at the so-called u-values[61], the strictest codes are found in Sweden, followed by Denmark (10% higher), Norway (20% higher) and Finland (30% higher). Generally speaking, strong building codes exist already in Sweden, Denmark, Finland, France, Germany, Ireland and the United Kingdom (Lautsten 2007, IEA 2009e).

Studies in the UK show that somewhat more stringent codes are as cost effective as less ambitious ones (Shorrock, 2009). A further incentive is to offer subsidies combined with requirements that are stricter than the minimum. This can create markets for innovators which will be followed by other builders when the building codes are updated regularly. Austria has done this successfully. Such effective approaches combine attention to innovators with stable and long-term oriented rewarding systems for the majority of players and standards for those lagging behind, including enforcement possibilities and sanctions (Tambach, 2010). The essence of a useful approach is to organise learning from each other.

This is the way ‘passive houses’ are entering the market. A passive house is a building in which a comfortable indoor climate can be obtained without a traditional heating or cooling system; heating amounts to 10 - 15 kWh per m^2.[62] Compared with traditional houses they use up to 70 - 90% less energy than current requirements. These houses no longer need a traditional heating system, which saves both energy costs but also investments, Over 30 years the total costs of these houses are lower than for houses complying with the current codes in a country such as Germany (with an oil price of 60 $ per barrel) (Lautsten 2007). Other estimates show that these houses might be marginally more expensive than less efficient ones; they range from 5 to 20% more expensive to a figure of 12,000 € (Daniels et al, 2006). This depends on the situation, estimates of other energy costs and financing. By offering favourable financial packages in the province of Upper Austria more than 10% of *all* single family houses now are passive houses. A general conclusion is that “studies show that in many (European) countries the efficiency (of new buildings) can be reduced by 70-75% without no or little additional total costs for owners” (Lautsten, 2007). This will often correspond to a passive house. With a higher level of diffusion, costs will decrease. Zero Energy Buildings are now relatively expensive, but these buildings can become feasible in the next 10 - 20 years.

An indirect effect of standards for new buildings is that they influence the efficiency of existing buildings as energy efficiency technology becomes cheaper and building companies are getting used to it. Indeed, the real problem is the existing building stock. Almost no country has found a good regulatory approach. Several attempts have been made and proposals have been developed (Tambach, 2010). For individual house owners, it seems most logical to combine an obligation

[60] Most standards address the building envelope, but as they improve the regulations also focus on the electricity systems and even other installations, and renewable energy.
[61] The u-value is a technical value describing how much energy passes through one square meter of construction by a difference of one degree in temperature.
[62] The formal definition of a passive house includes total primary energy consumption including all electricity.

to improve the label of the Buildings Directive with natural investment moments such as removal or renovation. Obliging energy performance standards and corresponding actions for existing buildings, e.g. when they are sold, also has legal implications affecting the European fundamental right of property. On the other hand, studies indicate that energy efficiency investments increase the value of dwellings: in the United States a one dollar investment might lead to a 20 dollar value increase (Nevin, 2010). More possibilities exist for housing stock owned by local governments or housing associations. In Scandinavian countries, France, the United Kingdom, the Netherlands or Austria this is some 25 - 35% of the total stock. For such houses, a more standardised approach seems more cost effective (like the 'street-by-street' approach as proposed in the UK). In practice, these might be combined with efforts to offer upfront finance (either by financial institutions and tax exemptions, or by energy companies in the framework of efficiency obligations, or both). A logical approach is to combine the rent - which often is maximised - with the energy performance certificate. In the Netherlands, for example, housing associations are allowed from 2010 onwards to increase the rent accordingly with a higher efficiency level of the certificate, but due to lower energy bills for tenants their overall monthly cost will decrease. In this way a largely subsidised social housing sector would be used to stimulate the privately owned sector and encourage long-term technology growth and market evolution (Jenkins, 2010).

It is up to the member states to find an appropriate solution, but much information and advice will be needed. It will also remain difficult as low energy refurbishment deviates from traditional renovation processes and work habits. Anyway, it has to be made easy for house owners to improve their buildings, otherwise it will not happen. It might be costly, but this is not necessary. Eco-refurbishments could be up to 15% more expensive than normal ones, but here a trade-off between ambition and costs may be observed. A slightly improved refurbishment is fully cost-effective. A high ambition certainly costs money and has a long pay-back period. An obvious solution is to begin with a gradual improvement and repeat this with a next removal. But this cannot be done in apartment blocks. Therefore, a trade-off remains. Due to the higher savings potential, regardless of the higher upfront investment costs, the pay-back period for older dwellings is shorter than for younger ones. Investments at natural moments like removal, replacement of the boiler or refurbishment are considerably lower than at another moment (Vethman, 2009). In all, the costs have to be put in perspective.[63]

Box 6.1 *Local initiatives: the German city of Freiburg*

One example out of many is the German city of Freiburg. Despite an increase in population of 10% in 1992-2007, it managed to decrease CO_2 emissions in that period with 13.7% without a disproportionate change in the economic structure. Three approaches were decisive:

- improved alternatives for urban car transport by improving the tram network and bicycle paths, next to increases in parking prices for cars;
- more ambitious standards for new buildings than the national ones. The current standard is 50 kWh per ^{m2}, which will be improved to 15 kWh in 2011; this is the equivalent of a passive house. A part of this approach is a huge stimulus of solar PV, not only financially, but especially by making it easier for investors to install the panels;
- a combination of standardised loans for energy-efficient renovations of existing houses with local and national subsidies.

Other countries like France or Denmark show the same pattern of local authorities as 'trend setter' of innovative policies.

Source: Financial Times, 6 November 2009.

[63] The initial capital cost investment to retrofit half a million dwellings in social housing in the UK would cost between 3.9 and 17.5 billion UK Pound. Since 2000 the annual subsidy spent by the UK government is some 20 billion.

Especially in existing buildings financing has to be a part of the package, as upfront costs of refurbishment are high. The provision of information and low-interest loans combined with advisory schemes has been an effective approach (Schule, 2009). At least three ways are feasible to attain this: low interest loans by banks, subsidies or tax incentives, finance by white certificates.

- An interesting example of low interest financing by banks is provided by the German Kreditanstalt fuer Wiederaufbau (KfW, Federal Loan Corporation). KfW contributed to retrofitting more than 1 million dwellings in 1995-2006 through provision of preferential rate loans for houses that meet or exceed standards for newly-built dwellings. Apart from low-interest loans, the KfW provides subsidies to owners of owner-occupied or rented houses. Subsidies of 10% of investment costs are provided in case the standards for newly built dwellings are met, or 17.5% in case they are exceeded with at least 30%. France provided a good example, which is one of many more, by recently renewing its commitment of offering a 0% interest rate loan for home retrofitting energy efficiency projects up to € 30,000.
- France also has a low VAT for such kind of refurbishments. Bulgaria has introduced a building tax exemption for up to 10 years to owners of buildings who have obtained energy performance certificates of the higher classes.
- White certificates are expressions of obligations for electricity and gas companies to attain a certain level of energy efficiency among their consumers. Denmark, the United Kingdom, France and Italy have achieved positive results with such obligations. Specific energy demand reductions of 1 to 3% of overall demand may be reached after several years and maybe more afterwards as in general the approach is first to establish targets and to strengthen them after a certain period. Especially in the UK this has resulted in large upfront financing by utilities for refurbishment of existing houses (Boot, 2009). In the United States positive results have been achieved as well. In the US cases no upfront capital had to be invested by the consumer, but a surcharge on the tariff was compensated by a lower volume of energy demand. As the surcharge was tied to the location and not to the individual, an eventual removal of the investor was still possible (Johnson, 2009). White certificates may hugely contribute to overall packages, but alone they will not lead to substantial reductions in demand. Denmark is the only country addressing small industry with the efficiency obligation.

An area of concern is the lack of enforcement of national energy efficiency laws and policies (IEA 2009c). According to the EPBD all new buildings must be certified by an independent expert. Countries like Portugal and Denmark therefore have introduced new regulations. In Denmark investigations showed that two-third of the new buildings failed to meet the requirements for some aspects of insulation (Lautsten, 2007). But enforcement is an issue of much broader interest. The Netherlands has an ambitious environmental law that obliges companies to take all measures that have a payback period of less than five years. As enforcement is sloppy, the effectiveness of this law is much lower than possible and better enforcement alone would reduce national greenhouse gas emissions with 0.5 to 1% (ECN analysis).

6.6 Are the targets feasible?

Lechtenbohmer et al (2009) offer an authoritative view on the relative contributions of different policy instruments. They modelled how the EU 20/20/20 target could be attained and how it could be improved to a 30% GHG reduction in 2020, which is in line with the *Roadmap 2050* ambitions. In a 30% GHG reduction scenario 41% of the reduction would be realised by energy efficiency improvements, of which 49% in the residential sector and 29% in industry. Therefore, the residential sector has to deliver the largest share of efficiency increase. The buildings and industry package consisted of the following elements:

- 30 to 40% of new buildings in 2020 had to be energy passive, with improved compliance.
- The refurbishment rate to improve efficiency of existing buildings had to increase from 1 to 2% per year due to strong policies.

- Improvement of ETS along the lines as suggested in Chapter 2; implementation of best available technologies under the IPPC directive and voluntary agreements in industry as applied in Finland or the Netherlands to construct forward looking efficiency packages.

In the meantime, policy thinking has continued. The EPBD recast requires that all new buildings be ‘near net zero energy’ by 2020. To contribute to deep emissions cuts by 2050, refurbishment rates have to increase to 2 - 3% annually.

The scenario modelling concludes with the remark that attaining the 20% efficiency improvement by 2020 is *crucial* for a 30% GHG reduction and thereby the *Roadmap 2050* ambitions.

An evaluation of existing and additional policies has to take the so-called rebound effect into account. Rebound implies that, due to lower costs of more efficient houses, cars or appliances, people will tend to use more (direct effect) and they will spend the income they saved through efficiency (indirect effect), which can be considerable. A recent analysis (Barker et al, 2009) assumed a direct rebound effect of 10% in transport and 25% in buildings; another study (Jenkins, 2010) assumed 30% in the case of low-income houses in the United Kingdom (before insulation people were simply too poor to heat their homes sufficiently). Therefore, up to a quarter of efficiency improvements will ‘leak away’ (of course contributing to a higher welfare level). This is a reason why in the long-run a target to reduce CO_2 emissions might be more effective than energy efficiency targets. This issue will be addressed in Chapter 8.

6.7 Conclusions

Policy matters! “If the impacts of a set of policy measures represent the total policy effort, an overall relationship between policy effort and realized energy savings emerges”, concluded Boonekamp and Eichhammer (2010) in a recent comparison of energy efficiency policies of EU member states and efficiency change in the period 1990-2004.

In this chapter a number of conclusions were drawn. First of all, to attain a 20% efficiency improvement by 2020 is crucial for reaching the *Roadmap 2050* ambition. But, the EU and its member states are not on the right track. Not only is the 20% efficiency improvement target not within sight, in a longer term perspective the impact of efficiency policy has to increase considerably. No real urgency can be observed that this aspect of energy policy, which is both most rewarding and most difficult, has to intensify considerably. The EU and its member states, having been front runners in global efficiency policies in the past, are now lagging behind.

Secondly, this is mainly caused by insufficient implementation of policies. Different countries show impressive approaches and new instruments are under consideration everywhere. But in all, it takes too much time to come to decisions and implement them.

Thirdly, no fundamental new instruments are needed. This is a positive aspect, as it takes much time to develop completely new approaches. But member states can learn much more from each other and adopt successful instruments that have a good track record elsewhere. The targets have to be ambitious, measurable in an easy way and monitoring has to be straightforward. For example, they could be based upon work being done in the Odyssee-Mure project, in which a combination is searched for between ‘top-down’ (such as Table 6.1) and ‘bottom-up’ (case by case) measurements. Another example is the IEA analysis of efficiency indicators. Clearly, the ambitions have to be much higher than what would be attained by autonomous improvements without additional policy. Different analyses conclude that a two to threefold improvement of the effect of energy efficiency policies is needed. This could imply an annual target of at least 1.6% energy efficiency improvement in the next decades, if the structure of the economy indeed becomes less energy intensive as expected by ECF. If the structural change is somewhat less than what is assumed in the ECF analysis, the target would be even higher. These are impressive figures, but certainly not out of reach by means of resolute policy.

Fourth, such approaches always consist of policy packages. If a few elements of these packages have to be named, they could be:

- An introduction of standards for new dwellings to ensure that at least half of the new buildings are passive houses by 2015 and 100% by 2020. A discussion is underway whether the EPBD should include a 'near net zero energy' ambition for new buildings by 2020. It is not fully clear what this would imply, nor what the additional costs would be in different countries. The closer the actual target could be to this ambition, the better it would be as long as additional costs could be paid back in a period comparable with the lifetime of an average period of amortisation, say 30 years.
- An extension of the EPBD to all existing buildings to ensure that annually 2-3% of the building stock will be refurbished in all member states, to take place with removal or general renovation, in which owners and tenants are obliged to improve the efficiency of their homes; to ensure that social housing organisations take the lead in this approach and are innovate, teaching the construction sector that efficiency improvements are possible and training workers. This will require effective delivery mechanisms such as establishing quality controls for the information and retrofit installations provided to households.
- Different ways of dedicated, consistent public funding would be needed to leverage private investment, such as upfront financing by means of low interest loans or tax reductions. Additionally, member states would have to organise sufficient enforcement and verification of these regulations.
- Automatic adjustment of Ecodesign standards and labels to technological improvements.
- To consider the introduction of energy efficiency obligations for utilities (white certificates) and other ways to create new business opportunities along the energy efficiency chain to spur innovation and productivity improvements. To be effective, energy efficiency obligations must have sufficient ambition, which will take some time as the success of the approach in countries like Denmark, the UK, Italy and France has been possible due to a gradual tightening of the targets enabling utilities to gain experience.

And finally, different levels of governance could cooperate in more efficient ways: the EU as a whole with member states and national governments with local authorities. This movement has started already, but the joint learning approach may be larger and more effective.

The toolbox of policies is well-known. High-level, long-term political commitment is needed to attain it. This is the reason why ECN's advice is to evaluate within the term of this Parliament whether the actual non-binding targets are on track and to reconsider this policy, including the option of a legally binding target if this is not the case.

7. Transport

7.1 Introduction

In 2006, transport accounted for 31% of energy use and 19% of greenhouse gas emissions in the EU-27 (Eurostat, 2009). Figure 7.1 presents a breakdown of emissions over the various transport modes. Clearly, the bulk of the emissions comes from road transport.

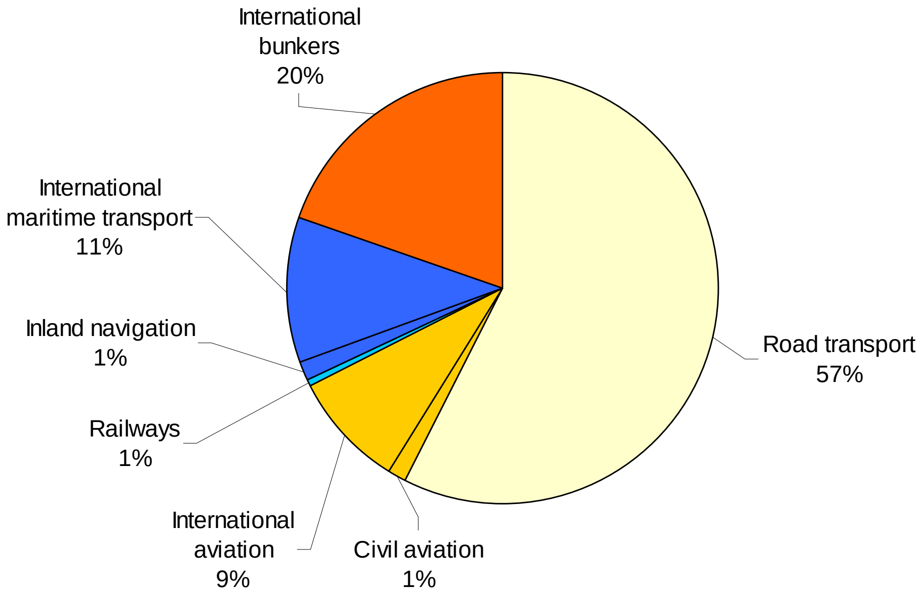

Figure 7.1 *Emissions of greenhouse gases by mode of transport in EU-27 in 2007*
Source: European Environmental Agency, 2009.

This chapter will examine options for reducing greenhouse gases in transport. The first section introduces a framework for analysis. More context is provided in Section 7.2, which puts policy measures for emission mitigation in a transport context, and in Section 7.3, which addresses the limitations of biofuels.

Options to reduce emissions in various transport modes are explored against this backdrop in Sections 7.5 to 7.8. Each section first discusses technical options, followed by a discussion of appropriate policy options. Finally, a separate Section (7.9) has been devoted to the introduction of hydrogen and electricity in road transport. Section 7.10 provides a brief conclusion.

7.2 Framework

Four factors contribute towards the emission of greenhouse gases from transport (King, 2007), as shown in the following equation[64]:

$$\underset{[kg]}{\text{GHG emissions}} = \underset{[\text{km}]}{\text{distance travelled}} \times \underset{[\text{factor}]}{\text{driving efficiency}} \times \underset{[\text{litre/km}]}{\text{vehicle efficiency}} \times \underset{[\text{kg/litre}]}{\text{fuel } CO_2 \text{ efficiency}}$$

Several options to reduce *distance travelled* exist. For personal mobility, the options range from mobility management, a package of ‘soft’ measures such as telecommuting and carpooling, to

[64] Reductions may also result from modal shift, i.e. the increase in use of less emission-intensive modes of transport. Although useful, modal shift cannot deliver the reductions that are aimed for in this report.

road pricing. For commercial transport, improved operational practices can lead to some reductions in distance travelled. In the long term, spatial planning can impact distance travelled by preventing urban sprawl and increasing urbanisation.

Driving efficiency can be increased by changes in driving style. In public transport and goods transport, increasing occupancy and load factors improves efficiency. Information campaigns to promote 'Eco-driving', lower speed limits, and Intelligent Transport Systems (ITS) are policy options to increase driving efficiency in private transport. Influencing the modal shift to increase the share of more efficient modes also improves overall driving efficiency.

Improvements in *vehicle efficiency* are brought on by technical advancement and downsizing[65]. For various transport modes, several minor and major adaptations to current technology are available. Although these adaptations may repay themselves over the lifetime of a vehicle, policy may be required to overcome their initial cost.

The reduction options that follow from these three factors are relevant, useful, and - taken together - robust. However, they do not lead to emission reductions of the order of magnitude that are considered in this report.

Increasing the *fuel CO_2 efficiency* is therefore the only option to achieve major reductions in the emission of greenhouse gases[66]. Practically, this implies using alternative fuels. Biofuels, electricity, and hydrogen are generally considered to be the most promising alternatives. Technically speaking, the latter two are not fuels, but energy carriers, i.e. they need to be produced from primary sources of energy (King, 2007). Their production processes, as well as extraction/farming of the primary energy source and distribution of the finished product, leads to emissions of greenhouse gases (Figure 7.2).

A proper analysis takes these chain emissions into account. The emissions of alternative fuels, as measured over the entire chain, can be lower than emissions of conventional fuels[67]. The CO_2 reduction potential is 100% only if the entire production pathway is carbon-free. Carbon-free production pathways exist for hydrogen and electricity, but these are energy-intensive and expensive. Other pathways (that do entail carbon emissions) are more likely to be deployed, at least initially. Emissions from these pathways can be captured and stored, albeit at a cost - both in monetary terms and in terms of energy. In those pathways, emissions are produced in a limited number of industrial sources. Hence, these producers should be included in the EU ETS to curb the chain emissions.

Carbon-free production of biofuels is more complicated. Production chain emissions for biofuels come from a variety of sources, varying from direct sources (such as the use of farming equipment and distribution trucks, and energy use during production and processing) to indirect sources (such as land-use changes). Biofuel production chain emissions depend on a number of factors, including the type of land and type of crop used.

[65] Here, downsizing refers to designing cars with lower weight and power. Downsizing may also refer to reducing engine displacement while keeping constant (or even improving) engine power.

[66] CO_2 is not the only greenhouse gas, but it is the only greenhouse gas produced in significant amounts in transport. Hence, the analysis in this chapter will be restricted to CO_2 only.

[67] Vehicles powered by hydrogen or electricity stored in batteries do not produce CO_2 tailpipe emissions. The CO_2 tailpipe emissions cars that run on biofuels are offset by the CO_2 absorbed as the feedstock grows.

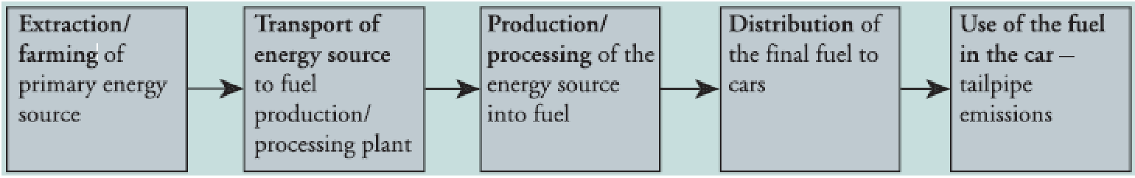

Figure 7.2 *Stages in the life cycle of a fuel*
Source: King, 2007.

The remainder of this chapter will focus on the emission reductions from improving vehicle efficiency and fuel CO_2 efficiency. The technical policy options that offer these reductions are discussed in Sections 7.5 to 7.8.

Such a discussion is only useful in the proper context. This context is provided by the next two sections that elaborate on the implementation of policy measures in the context of transport (7.2) and the limitations of biofuels (7.3).

7.3 Policy measures in the context of transport

Besides the government sector, the following actors are relevant in the transport sector:

- *Vehicle producers*
  Vehicle producers can be stimulated or required to implement design changes that reduce emissions.
- *Fuel providers*
  Fuel providers can be stimulated or required to improve fuel CO_2 efficiency.
- *Consumers*
  Consumers can be stimulated or required to reduce the number of vehicles that they purchase, to purchase more efficient vehicles, to buy lighter or smaller vehicles, to reduce vehicle use, and/or to use their vehicles more efficiently. Note that consumers can refer to private persons and transport companies in this context.

Policy will attempt to influence the decisions and behaviours of these actors. Some policy measures are more appropriate than others in the context of transport (Smokers et al., 2009):

- *Fiscal policy*
  Fiscal measures can be targeted at the purchase and use of vehicles by consumers (private persons as well as transport companies). Fiscal measures are typically established at the member state level. Taxes can be differentiated based on CO_2 emissions, which have already been implemented by some member states.
- *Cap-and-trade (EU ETS)*
  The feasibility of cap-and-trade systems differs per sector and per actor that is affected. Targeting fuel providers and/or vehicle producers is generally difficult, because they have limited influence on the fuel consumption of their customers. Targeting consumers is only practically feasible if their number is limited. Consequently, aviation, rail, and shipping are candidates for inclusion in the EU ETS, whereas road transport is not.
- *Standards and regulations*
  This is the policy instrument that is most widely used at the EU level and can be applied within the existing legislative and policy context. Corporate entities, i.e. vehicle producers and fuel providers, are most easily targeted by standards and regulations.

The abovementioned policy measures are generic. Additionally, new technologies to improve vehicle and fuel CO_2 efficiency may require specific policy support to overcome barriers to introduction.

In conclusion: emissions trading is a viable policy measure for aviation, rail and shipping, but not for road transport. Fiscal policy and standards and regulations are additional policy measures that can (and need) to be put in place in all transport sectors.

7.4 Biofuel availability and sustainability

Only minor adaptations to current technology are required to deploy biofuels. Hence, biofuels are a viable substitute for conventional fuels for all transport modes. However, projections show that the total amount of biofuels available is limited. Figure 7.3 shows a projection for OECD Europe in the BLUE Map scenario, derived from the IEA Energy Technology Perspectives (IEA, 2008). In this scenario, greenhouse gas emissions in 2050 are half the 2005 emission levels, similar to the ambitions in the Roadmap 2050 project. It includes vehicle efficiency improvements of 30% to 75% and travel demand reductions of up to 15%.

Energy use covered by hydrogen and electricity is not included in Figure 7.3. The remaining energy therefore needs to be covered by liquid fuels. Clearly, biofuels are not able to close the supply gap for OECD Europe. The IEA analysis shows that the gap is even larger worldwide. This leads to several conclusions. Firstly, reducing fuel demand through reduction of travel demand, driving efficiency and vehicle efficiency is of the utmost importance. Secondly, biofuels should be reserved for transport modes that cannot switch to another energy carrier to a significant extent before 2050. Thirdly, development of alternative technology for the longer term (i.e. beyond 2050) should be pursued for modes that can only rely on biofuels before 2050. Finally, a complete reduction of emissions from transport might not be feasible by 2050 - although very substantial reductions are possible.

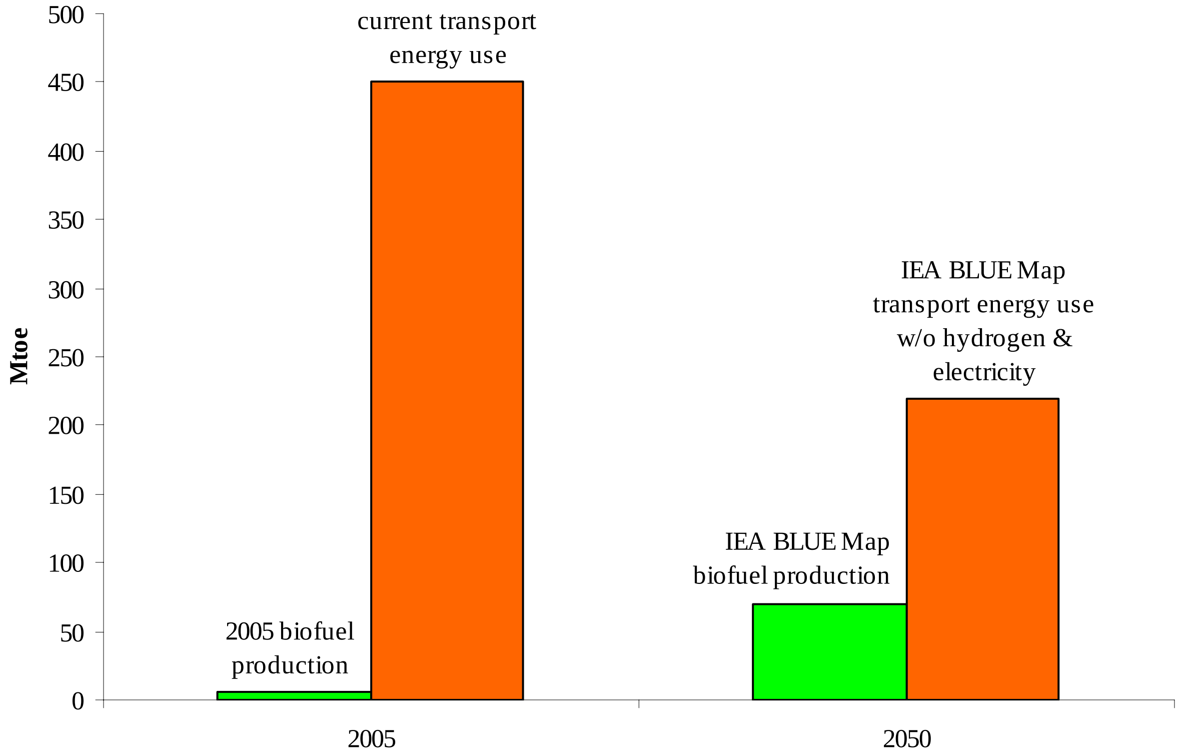

Figure 7.3 *Projections of biofuel production versus energy use in transport (excluding hydrogen and electricity use) in OECD Europe*

Additionally, the sustainability of biofuels is currently debated (Bauen et al., 2009). As discussed in Section 7.1, although tailpipe emissions of vehicles powered by biofuels are compensated by take-up of CO_2 when feedstock grows, emissions in other parts of the production chain may offset this compensation. Furthermore, so-called first-generation biofuels may compete for resources with food, driving food prices up. Moreover, biofuels can have a negative impact on biodiversity.

Therefore, policies that aim to increase the use of biofuels should be carefully designed to favour biofuel use that minimises these negative impacts. A properly designed set of policies can mitigate the production chain emissions from biofuels. Some direct emission sources (such as industrial sources and agriculture) can be included in the EU ETS[68]. Other, indirect emission sources, as well as negative effects on food prices and biodiversity, can be mitigated by stimulating the use of favourable types of feedstock and land, e.g. by letting these types of fuels count double towards achieving targets in a Regulation[69].

The following conclusions may be drawn from this concise description of biofuels availability and sustainability**:**
- Policy aimed at reducing travel demand and improving efficiency is very important to narrow the biofuel supply gap.
- Policy should primarily aim to stimulate the use of biofuels only in sectors for which no other alternative fuel is available.
- The sustainability must be taken into consideration, including the effects of indirect land-use change. It must be assured that only biofuels are used that substantially reduce emissions of greenhouse gases over their entire life cycle.
- R&D support is required for long-term (beyond 2050) alternatives to close the gap that cannot be covered with alternatives that are expected to enter the market until 2050.

7.5 Road transport

Passenger cars and light-duty vehicles
Passenger cars and light-duty vehicles (LDVs) are responsible for the bulk of energy use and emissions in road transport. Consequently, reducing emissions from these vehicles has a large impact in absolute terms.

Technical options
Increases in vehicle efficiency are available from changes such as improving design of the internal combustion engine (ICE), fitting cars with low-friction tyres, and applying lighter materials. Improving vehicle efficiency is expected to bring down new vehicle fleet emissions to approximately 85 grams of CO_2 per kilometre, using ICE technology (Sharpe and Smokers, 2009). To achieve reductions below this level, car manufacturers have to resort to reducing car size and fit cars with less (energy consuming) appliances.

Further emission reductions must come from improving fuel CO_2 efficiency, i.e. the introduction of alternative fuels. Biofuels, hydrogen, and electricity are all viable alternatives for fossil fuels in passenger cars and LDVs.

The introduction of biofuels is not complicated from a technical point of view. Biofuels can be blended into conventional fuels and used in conventional engines without a need for technical adaptations (De Wilde and Londo, 2009). Minor modifications are required for blends with larger shares of biofuels.

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68 Note that this can put biofuels at a cost disadvantage vis-à-vis conventional fuels. Policy to curb production chain emissions from biofuels should therefore be carefully designed. Research on this subject is currently carried out (e.g. Elobio, www.elobio.eu).

69 The Renewable Energy Directive (28/2009) already includes such provisions. To be able to determine the chain emissions of biofuels, detailed study of each type of feedstock is required. In general, so-called second-generation biofuels tend to have a more favourable CO_2 balance as measured over the entire chain.

Another viable option is to use electricity to power cars and LDVs. Electricity can be stored in batteries or produced from hydrogen in a fuel cell[70]. Electric vehicles - both fuel cell electric vehicles (FCEVs) and battery electric vehicles (BEVs) - are more energy efficient than conventional vehicles. Their introduction would thus impact both fuel CO_2 efficiency and vehicle efficiency, provided the hydrogen and electricity have been produced in low-carbon or even carbon-free pathways.

Incorporating elements of electric vehicles can make conventional vehicles more efficient, and reduce emissions below the levels that can be achieved using an ICE only. In the hybrid electric vehicles (HEVs) that are currently commercially available, an electric motor functions as an auxiliary power source. In this configuration, the performance of a conventional vehicle can be achieved with a smaller ICE that produces less emissions. Current HEVs are not designed for propulsion using only the electric motor over longer distances.

Several vehicle manufacturers are preparing market introductions of plug-in hybrid vehicles (PHEVs) that can be operated in 'electric only' mode. The batteries of these vehicles can be recharged from the electricity grid, so that using only electricity as energy source is possible on short trips. In that sense, PHEVs are similar to BEVs. However, PHEVs come equipped with an ICE that powers a generator to recharge the batteries on longer trips or can drive the vehicle directly. Therefore, the range of a PHEV is similar to the range of a conventional vehicle.

Implications for policy

A significant reduction in emissions of cars and LDVs calls for two sets of policies: generic and technology-specific. A generic set of policies must assure that emissions from conventional vehicles are reduced. Both vehicle producers and consumers are involved in the introduction of new vehicles, and policy must address these two actors.

Vehicle producers must be required to ensure that emissions from new vehicles do not exceed certain standards. Currently, EU Regulation 443/2009 requires that emissions from new passenger cars do not exceed 130 grams of CO_2 per kilometre by 2012[71]. Using this Regulation, more stringent targets can be set, eventually requiring manufacturers to sell only cars that have no tailpipe CO_2 emissions. How fast the targets can be lowered depends on the development of BEVs and FCEVs (see Section 5.8) but the 95 gr/km target for 2020 is technically feasible using current technology and should be committed to. Depending on technical progress and market acceptance, manufacturers can probably be required to sell only zero-emission cars around 2035, with an intermediate target of approximately 40 gr/km around 2028.

Additionally, emission standards should provide manufacturers with an incentive to reduce emissions even further than formally required. This can be achieved by double counting of vehicles with extremely low emissions and by communicating that stricter standards will be introduced in the mid to long term[72]. Double counting must be based on realistic assumptions - specifically on calculating the CO_2 emissions from electric vehicles based on the current energy mix. If this is not done, double counting may water down fuel efficiency standards.

On the consumer side, the two factors determining CO_2 emissions are vehicle purchase and vehicle use. Most appropriate policy is fiscal measures, to be established at member state level.

[70] Technically, a variety of fuels can be fed into a fuel cell. Using hydrogen as a fuel does not produce any CO_2, hence the majority of research is concerned with the application of hydrogen in fuel cells.

[71] Calculated as the average of emissions of all newly registered cars in a particular year. The Regulation is phased in starting 2012 and will be fully effective in 2015.

[72] Under Regulation 443/2009, vehicles with emissions less than 50 grams of CO_2 per kilometre are counted more than once. The Regulation also sets 95 grams of CO_2 per kilometre as an indicative target for 2020. It is important that such targets are set realistically. Only PHEVs are able to produce emissions less than 50 gr/km. However, only a few manufacturers prepare PHEV introduction, none of which achieve the target. Hence, it can be concluded that the target has been set too stringently and has not sped up the introduction of PHEVs.

Registration tax can be altered to take emissions into account thus influencing the choice of vehicle. Vehicle use can be influenced by factoring emissions into the road and fuel taxes.

The consequences of this policy are likely to be twofold. On the one hand, it will lead to the development and sales of more efficient conventional vehicles that produce fewer emissions. As standards tighten and can no longer be met by efficiency improvements in ICE technology, manufacturers are likely to introduce HEVs and PHEVs. Hybridisation is thus a robust option to reduce emissions.

On the other hand, vehicle manufacturers are provided with incentives to develop vehicles that use alternative technology. Such a development allows manufacturers to achieve long-term emission standards. Furthermore, sales of vehicles with (extremely) low emissions can offset emissions of vehicles in the top of the product range.

Nonetheless, a set of generic policies applying to all vehicles is insufficient to overcome all barriers associated with a large-scale introduction of alternative technologies. Consequently, a set of policies that stimulates the development and introduction of alternative fuels and associated technologies must be put in place. Each of these policies needs to be tailored to the technology that it targets. Section 7.9 presents a detailed discussion of this set of policies.

The following policy measures are suggested for light-duty vehicles:
- A gradual, but ambitious tightening of standards for average emissions of new vehicles is necessary.
- Factoring emissions into fiscal measures on purchase and use of light-vehicle vehicles are most appropriate.

Heavy-duty vehicles
Heavy-duty vehicles are made up of long-haul trucks, distribution trucks and buses. Options to reduce emissions vary among these vehicle types.

Technical options
For all of these vehicles, vehicle efficiency improvements of 15% to 30% are possible using ICE technology (TNO, 2008; Lensink and De Wilde, 2007; Hanschke et al., 2009).

Further reductions must come from improvements to fuel CO_2 efficiency. Biodiesel offers a feasible alternative for all HDVs. For long-haul trucks, biodiesel is the only feasible alternative. Batteries cannot supply long-haul trucks with sufficient energy for the range they require. Moreover, refuelling or recharging would take prohibitively long. Hybridisation is also not an option for long-haul trucks, because these trucks are generally operated at constant speeds and power[73]. Whether hydrogen is a feasible alternative fuel depends on possible advances in hydrogen storage technology.

Hybridisation does offer efficiency advantages for buses and distribution trucks, leading to estimated emission reductions of 25% to 55% (CE, 2008; Passier et al., 2008). Using only electricity stored in batteries to power buses and distribution trucks provides only a limited solution, due to the low amounts of energy that can be stored in batteries. Successful pilot projects have proven that powering buses with hydrogen is a feasible option (Hoen et al., 2009). Distribution trucks using hydrogen have not been extensively tested yet, but are technically feasible as well.

Implications for policy
Policy should seek emission reductions through improvements of existing technology in the short term, and introduction of alternative fuels and technology in the long term. On the manufacturer side, improvement of existing technologies can be induced by introducing emission

[73] The efficiency of electric motors is only distinctly superior to that of ICEs for transient loads.

standards for HDVs. This may be achieved by amending existing regulation setting emission standards to include emissions of CO_2. Note that this requires devising a procedure to translate the current type of approval test at engine level to CO_2 emissions per vehicle (Smokers et al, forthcoming).

The consumer side consists of transport companies. Fiscal measures (e.g. CO_2 tax differentiation) can stimulate the uptake of efficient vehicles and reduce (inefficient) vehicle use. Note that transport companies will more likely consider the total cost of ownership when making investment decisions than consumers, implying that the impact of well-designed fiscal measures is higher for transport companies than for consumers. Governments may set examples in public transport, where publicly-owned companies can procure clean vehicles or criteria setting emission standards can be included in tenders for public transport.

Note that both fiscal policy and investment decisions for public transport are set at member state level. It is possible that successful fiscal policy requires harmonisation, as companies are likely to base their operations in the states with the most favourable tax regimes. Further research on the extent to which harmonisation is necessary for successful introduction of fiscal policies is recommended.

Long-term policy must be aimed at the introduction of technology for alternative fuels. For long-haul trucking, one option could be to design policy directed at increasing the use of biodiesel, if their sustainability and impact on emissions of greenhouse gases can be guaranteed. This can be achieved by requiring fuel suppliers to blend an increasing percentage of biofuels in their conventional fuels[74]. Further research on whether such a policy can be restricted to long-haul trucking only is recommended. To narrow the biofuel supply gap, research into long-term alternatives to long-haul trucking should be actively supported.

Introducing hydrogen as a fuel in distribution trucks and buses requires specific policy support. This is discussed in detail in Section 7.9.

It is suggested to consider the following policy measures for heavy-duty vehicles:
- Include and tighten CO_2 emissions in regulation.
- Factoring emissions into fiscal measures on purchase and use of new vehicles (EU member state level).

7.6 Aviation

Emission reductions of up to 70% per passenger-kilometre seem to be possible in aviation, provided that technical and operational options are fully pursued, including a switch to low-carbon fuels. However, because air travel is expected to grow substantially, total emissions are not expected to go down significantly (Hoen et al., 2009).

Technical options

Improvements in aircraft efficiency are technically possible, and the aviation sector is traditionally focused on minimising fuel costs. Changes take place slowly, however, since aircraft have a long lifespan.

Hydrogen and biofuels offer opportunities for improvements of fuel CO_2 efficiency. Recent tests show that blends of biofuels can be used in existing engines without major adaptations (IATA, 2009).

[74] As is currently stipulated in Directive 30/2009, also known as the Fuel Quality Directive.

Hydrogen requires substantial changes in aircraft design and the implementation of a new distribution infrastructure. Due to the slow replacement rate of aircraft, hydrogen is not expected to have a large impact on emissions by 2050.

Implications for policy
Since only a limited number of players are involved in the aviation sector, emissions trading is a viable policy alternative. The aviation sector will be included in the EU ETS from 2012 onwards. Inclusion of aviation in the EU ETS will also create an incentive to speed up the introduction of biofuels. Other measures include imposing an excise tax on kerosene and value-added tax on flights. As in road transport, a directive can be an effective instrument to require fuel providers to blend a certain percentage of biofuels in their jet fuel, provided the sustainability of biofuels can be guaranteed.

Due to the limited availability of biofuels, it is advisable that research on the use of hydrogen as an aviation fuel is actively supported. Specific policy support for the commercial introduction of hydrogen in the aviation sector is probably required as well, but unlikely to take place prior to 2050.

Therefore it is suggested to consider the following policy measures for aviation:
- Include aviation in EU ETS.
- Implement directive stipulating blending of biofuels in jet fuel.

7.7 Shipping

The shipping sector consists of inland navigation and sea shipping. Many vessels, particularly sea ships, are registered outside of the EU. A regulatory framework for shipping has been developed and maintained by the UN-based International Maritime Organization (IMO). A process to regulate emissions from shipping in the IMO is ongoing (Torvanger, 2008).

Technical options
Changes in ship design can improve efficiency of vessels used for inland shipping. For specific purposes, fuel CO_2 efficiency can be improved by hybridisation and by using electricity stored in batteries (Hoen et al., 2009). Hydrogen can also be used, although large quantities of hydrogen are needed and on-board storage space is limited (De Wilde et al., 2006). The use of biofuels seems the most feasible short-term option.

Due to their large size, sea ships transport their loads quite efficiently. Still, technical options (e.g. air lubrication) to further increase efficiency are available. However, such improvements will not reduce emissions sufficiently in the medium term. The energy density of hydrogen and batteries is too low to be used in sea ships. Biofuels do provide a viable alternative.

Implications for policy
CE (2006) concludes that including shipping in the EU ETS is a viable option to reduce emissions. An additional option is to differentiate harbour dues to include CO_2 emissions. A directive can be an effective instrument for the introduction of biofuels in shipping. This can be an extension of the Renewable Energy Directive (28/2009), which already stipulates the use of biofuels in transport. Due to the limited availability of biofuels, support for research on long-term alternatives is recommended.

In short, the following policy measures for shipping could be taken:
- Include shipping in EU ETS.
- Differentiate harbour dues to include CO_2 emissions.
- Implement directive stipulating the blending of biofuels.

7.8 Rail

Trains use either diesel or electricity from overhead wires. Here, only diesel trains are considered as producers of CO_2, because emissions of electric trains are part of the electricity sector. Consequently, emission reductions in the rail sector are best realised by replacing diesel trains by electric trains[75].

It is possible to include rail in the EU ETS. This should raise costs for operating diesel trains and thus provide an incentive for electrifying non-electrified stretches of railway. A side-effect to including diesel trains in the ETS could be that rail transport is put at a cost disadvantage compared to road transport, possibly leading to an increase in emissions. Therefore, policies should be designed in such a way that the relative position of rail does not deteriorate. Further financial incentives may be put in place to subsidise investments in electric infrastructure. Research is recommended to determine whether inclusion in the EU ETS would be a sufficient incentive for such investments or if additional measures are required.

In short, it is suggested to include rail in EU ETS.

7.9 Introducing battery electric vehicles and fuel cell electric vehicles

Part of road transport can be made entirely carbon-free by the introduction of FCEVs and/or BEVs. Currently, BEVs are moving into the demonstration phase of the technology development cycle (Figure 7.4). FCEVs are currently in the demonstration phase. The technologies require specific policy support to overcome barriers for introduction. The next sections examine how policy to overcome barriers to market introduction can be designed.

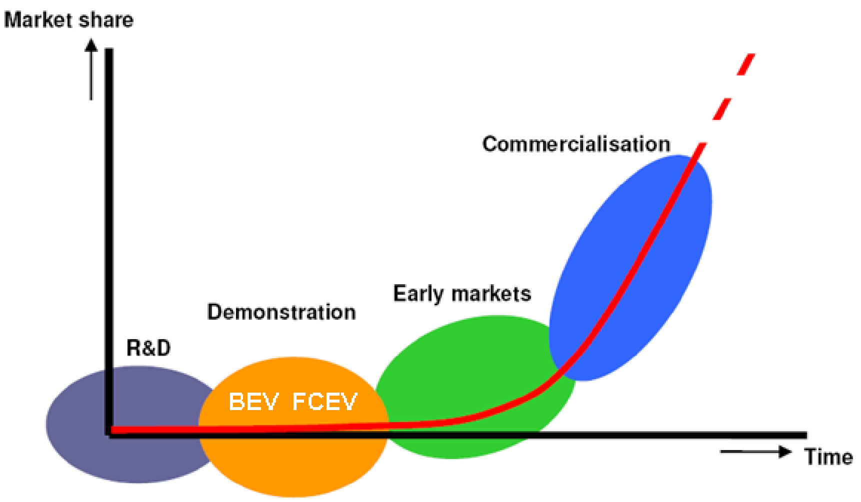

Figure 7.4 *Position of BEVs and FCEVs in the technology development cycle*

Specific policy for BEVs
The following are major barriers for the introduction of BEVs:
- *Costs*
  Electric vehicles are currently too costly to compete with conventional vehicles, primarily due to the high costs of batteries. Learning effects and economies of scale are expected to bring down costs as production volumes increase.
- *Infrastructure*
  Not all consumers have the possibility to charge vehicles at their home. Moreover, the limited range of BEVs necessitates the possibility to recharge at locations away from home. A

[75] Nonetheless, efficiency of electric trains can be improved significantly, e.g. by introducing regenerative braking.

network of charging points must therefore be installed. Additionally, the electricity grid needs to be strengthened to facilitate the large increase in electricity demand if significant numbers of BEVs enter the roads[76].

- *Mismatch with consumer preferences*
  BEVs cannot match conventional vehicles on all vehicle attributes. The most notable difference is the limited range that BEVs offer, especially in higher vehicle segments.

The following specific policy options can be pursued to overcome these barriers (Smokers et al., 2009):

- Provide financial support for R&D for batteries. Batteries are the most critical and expensive component of BEVs.
- Provide financial support for demonstration projects. Such projects can help manufacturers to improve vehicles so that they match consumer preferences as much as possible. Some learning may take place that can lower costs. At a member state level, governments can be lead customers and incorporate a number of BEVs in their fleets.
- Create stable market conditions for BEVs when they are ready to compete with and replace conventional vehicles and move out of the demonstration phase. This involves subsidising BEVs, e.g. through tax breaks and by stimulating new business models that lower the up-front costs of BEVs[77]. Government commitment must be large enough to provide industry with the prospect that there is a viable market for BEVs. Note that these are measures to be taken at member state level.
  Subsidising BEVs must be done with care. Subsidies should not allow the creation of a niche market for a car that is an addition to the existing vehicle stock rather than a replacement of existing vehicles.
- Support and coordinate the rollout of the complementary infrastructure. Consumers will be hesitant to purchase vehicles they cannot recharge.

Note that the focus of policy shifts from manufacturers to consumers and from public to private investments as the technology moves from the demonstration phase to the early market phase.

Specific policy for FCEVs
The following are the two major barriers for the introduction of FCEVs:

- *Costs*
  FCEV costs are currently too high to compete with conventional vehicles, primarily due to the high costs of fuel cells. Learning effects and economies of scale are expected to bring down costs as production volumes increase (HyWays, 2007).
- *Infrastructure*
  A distribution infrastructure for hydrogen must be put in place. Rolling out a hydrogen infrastructure is prone to the chicken-and-egg problem - vehicle manufacturers are unwilling to introduce vehicles for which refuelling facilities lack, while fuel providers are unwilling to put refuelling stations in place for vehicles that are not yet available.

The following specific policy options can be pursued to overcome these barriers (HyWays, 2007)

- Provide financial support to R&D. R&D must be targeted at bringing down the costs of fuel cells and of hydrogen storage.
- Once they have proven to be a viable option, create stable market conditions for FCEVs. Measures include incentives for consumers to purchase FCEVs, e.g. through tax breaks and subsidies. Governments can act as lead users by procuring FCEVs themselves. To overcome

[76] The number of BEVs (or PHEVs) that can be supported using existing infrastructure depends on local circumstances. Research on a typical new city district (in this case Dutch) shows that the electricity grid is able to support a significant amount of BEVs (up to 20%) before upgrades are required (De Boer-Meulman et al., 2009).

[77] There are other ways to lower the up-front costs of BEVs, such as new ownership models in which a consumer purchases the vehicle and leases the battery. Policy should be designed to accommodate such innovative models.

the chicken-and-egg problem, it is very important that both fuel providers and car manufacturers are convinced that a viable market for FCEVs and hydrogen sales will emerge.
- Support the rollout of complementary infrastructure. The extension of the electricity grid is a public affair. A hydrogen distribution infrastructure does not exist yet, and it can be financed by any combination of private and public funds. Providing financial support during the early market phase stimulates fuel providers to quickly build a network with sufficient coverage despite underutilisation. Additionally, clear safety standards must be established.

Concluding remarks
Support for either alternative is dependent on the success of the other alternative across the various vehicle segments. The success of an alternative in a particular segment depends on the technological progress, development of investment costs and operational costs, and the interaction with other segments (e.g. the ability to store surplus energy from intermittent sources in vehicle batteries). Note that synergies exist for the developments of both segments, e.g. (small) batteries used in both vehicles.

Finally, offering equal specific policy support might favour electric vehicles, since they can be introduced in larger numbers without substantial investments in infrastructure. This appears to be unavoidable. Nonetheless, commercialisation of FCEVs is not expected to start before 2015/2020 (HyWays, 2007), potentially providing BEVs with a ‘head start’.

7.10 Conclusion

Emissions from transport can be reduced by reducing distance travelled, improving driving efficiency, improving vehicle efficiency, and improving fuel CO_2 efficiency. Policies that reduce travel demand and improve driver and vehicle efficiency are robust. Although their potential to reduce emissions is generally underestimated, reducing travel demand and improving driver efficiency are likely to bring only modest emission reductions. Further reductions must come from improving vehicle and fuel CO_2 efficiency. Different technical and policy options to achieve these reductions are appropriate for different sectors.

The railway, aviation, and shipping sectors are candidates for inclusion in the EU ETS. For rail, the use of electricity to power the rolling stock should be encouraged. In aviation and shipping, the use of biofuels should be promoted, if their sustainability can be guaranteed. For all of these measures, (preparatory) action can already be taken now.

Severe concerns surround the sustainability of biofuels. Policy should therefore be carefully designed to mitigate possible negative effects resulting from the use of biofuels. Moreover, it is unlikely that biofuels will be able to fully supply all sectors for which no other alternative fuel is available in the short term. Other (long-term) alternatives should therefore be pursued in these sectors as well. It is therefore advised to review policy periodically (e.g. every five years) to determine whether new technical options have emerged that require specific policy support.

Inclusion in the EU ETS is difficult in the case of road transport. A generic policy that sets tightening emission standards is recommended to induce the development of alternative technologies. For light-duty vehicles, this implies using the 2013 revision of existing legislation to make the 2020 target of 95 grams of CO_2/km legally binding. For heavy-duty vehicles, it is advised to include CO_2 emissions in the existing regulation as soon as possible.

To achieve full decarbonisation, the larger part of the road transport sector (excluding long-haul trucking) is expected to use electricity from batteries or hydrogen as an alternative in the medium term. For these two technologies, technology-specific support is recommended. The timing of these policies depends on technological progress and consumer acceptance.

8. A Climate and Resource Directive

8.1 Introduction

With a long-term 2050 target in ETS, stability in the approach of the power and industrial sectors to achieve far reaching greenhouse gas reductions would have been created. A European 2050 target will guarantee emissions reductions in a cost-effective way. At this moment no comparable approach exists in the non-ETS sectors. This leads to possible lock-ins in investments and possible disequilibria when resources have to be allocated to different sectors. It will be argued in this chapter that a European directive to reduce greenhouse gas in other sectors in a comparable way could be a useful addition to the current policy instruments.

8.2 The Issue

In Chapters 2 and 3 it has been argued that a long-term approach is needed in the power sector to attain a nearly zero carbon emission by 2050. This requires two elements: strong technology development to open opportunities and reduce costs; and a strengthening of the EU ETS target including a clear intermediate emissions level. The ETS sector emits roughly half of the European greenhouse gases. This raises the general issue how other sectors - buildings, transport, services and smaller enterprises in general - may be incentivised to realise comparable reductions. At this moment Europe does not have a clear policy to attain its ambitions in these sectors. Useful partial approaches exist and they may be further improved, as has been sketched in Chapters 6 and 7. But although energy efficiency policies are necessary to attain strong reductions in CO_2 emissions, they are not sufficient.

Three reasons exist to consider a more regulatory approach in the non-ETS sectors:

- To guarantee that long-term emission reductions will be achieved. There is no alternative to formulating an overall long-term greenhouse gas reduction target in a Directive. In the buildings sector no leakage to other regions may occur by definition and in the transport sector it may be rewarding to guarantee a front runner position. A long-term energy efficiency target is useful, but not a viable alternative as (1) the impact on emission reductions is unclear because of the rebound effect (see Chapter 6) - it has been concluded that the only way to address the rebound effect is through the use of carbon taxed or a carbon cap (Sorrell 2009); (2) it would be impossible to formulate a specific, long-term efficiency target as the precise costs and benefits of specific efficiency targets and policies depend to a large extent on the economic growth; (3) energy efficiency takes a substantial part of the emission reduction but cannot guarantee a complete transformation to a nearly full decarbonised energy system. More overall approaches have to be searched for, as has been done for the power sector in this report.
- Without a long-term vision lock-ins may occur. A clear example is small-scale CHP. In the short run, small-scale CHP contributes to greenhouse gas reductions. But in the long run, emissions remain that cannot be decreased further. Therefore, small-scale CHP might deliver a contribution to a considerable decrease of greenhouse gas emissions, but won't suffice to attain a 95% reduction; to achieve that ambition different solutions have to be searched for right from the beginning - this is exactly why a back-casting approach that has to be complemented with policy instruments is useful. The same might be the case for the gas infrastructure in general. In the next decade, gas consumption will increase, mainly due to gas-fired power generation. But will this remain the case after 2020? Maybe not as - depending on the precise ECF pathway - gas imports might start to decrease. In that case some prudence would be needed with additional gas infrastructure. It is a clear example of a possible lock-in. Short-term improvements may block a long-term solution.

- A disequilibrium in resource allocation might occur. Biomass is an example. A strong ETS could stimulate the use of biomass in the power sector as this might be a relatively cheap way to increase the share of renewable energy in power. From the standpoint of immediately reducing carbon emissions it might even be better to use biomass to produce electricity than to produce liquid fuels (Lackner et al, 2010). But in the end biomass will be scarce (PBL, 2009). In some parts of transport (long distance trucks, shipping, air transport) the only way to decarbonise will to a large extent depend on the use of (sustainable) bio fuels. In a cost-effective overall approach it might be that scarce biomass has to be used in these parts of the transport sector, but to a lesser extent in the power sector. Therefore, an unbiased, overall long-term approach including all sectors is needed and only a combination of credible targets in different sectors is capable of achieving this.

8.3 A possible solution

The European Commission should consider proposing a Climate and Resource Directive that could oblige member states to reduce GHG emissions with 90% in 2050 in non-ETS sectors. The reduction ultimately could be implemented within Europe, which would imply that the share of low carbon investments elsewhere to attain the European ambition eventually has to be limited considerably. In this way the achievement of the target would be enhanced, stability in climate and energy policy would be improved and a solid investment climate would be created. The United Kingdom created a Climate Bill in October 2008. The Climate Law in the UK has introduced more certainty for investors and a different way of thinking. The Finnish parliament decided to consider a law to cut the country's greenhouse gas emissions by 5% every year. Germany is now also considering introducing such a law.

Box 8.1 *The United Kingdom Climate Law*

In October 2008, the UK decided to introduce a national Climate Law. This consists of 5 parts:
- Part 1 states targets in 2020 and 2050: -34 and -80% greenhouse gas reduction against a 1990 baseline respectively. The targets include the British part of air and international sea transport and may be achieved through actions within the UK and abroad. Every five years a Climate budget has to be decided upon in line with the long-term target. Within the budget an average of different years may be attained to avoid e.g. differences in average temperature. Every year policies and proposals to meet the budgets have to be reported to Parliament, together with the national budget proposals.
- A Committee on Climate Change - an independent, expert body - has been introduced that has to monitor the realised reductions and propose how the target of the climate budgets can be achieved. The Committee will submit annual reports to Parliament and the government must respond to them in the annual reports. The first report of the Committee was submitted by October 2009.
- The legal framework of an emissions trading system in non-ETS sectors has been established.
- The impact of adaptation to climate change will be assessed every 5 years and proposals how to deal with this will be made.
- Part 5 offers other options to deal with climate change.

It is not necessary to copy the UK approach. What could be considered is a long-term greenhouse gas reduction target and stability in the governance structure to achieve this. ECN suggested to consider how the EU ETS could do this for the ETS sectors, so the Climate Directive could look at non-ETS sectors only. The essence of the national laws is *that* member states want to achieve the 2050 ambition and *how* they want to do this. But details of implementation might be different from country to country. Whether or not EU members want to include adaptation issues is up to them. Cooperation in adaptation would be hugely beneficial, of course. The legal situation in member states will differ largely and therefore it is not strictly necessary to include a framework for national emissions trading systems. On the other hand, member states could decide to include other issues. For example, they could introduce a long-term target for renewable energy and/or CCS to create stability for investors and reward technological change.

An interesting aspect of the Climate and Resource Law could be the introduction of national caps and emissions trading in the buildings sector, coming to a head in gas and heating oil demand (CO_2 emissions of power demand are capped already by ETS). For example, national CO_2 allowances of gas consumption could be auctioned among utilities and may take the average expected temperature into account. A CO_2 price for gas and heating oil would balance gas and power demand in a fairer way and contribute to the diffusion of heat pumps. A possible variant is the Dutch Green4sure plan, developed by NGOs and the largest national Trade Union, which suggests three emissions trading schemes: ETS, a national cap and trade scheme in the buildings sector and a new cap and trade scheme for the transport sector (preferably at the European level) (Rooijers, 2007). Another variant could be a ‘personal CO_2 allowance’ (Fawcett et al, 2010).

8.4 Counter arguments and specific issues

Opponents of the proposal might give counter arguments. The first one might be that such a law might freeze economic development. A second argument might be that we need much more flexibility in deciding whether to attain a carbon reduction ambition within or outside Europe. A third argument could be that it cannot be enforced.

- *Economic development*. The fastest growing non-ETS sector is transport, so the ultimate question is whether and how transport can be carbon neutral. In Chapter 7 it has been suggested to continue the improvement of greenhouse gas emission standards after 2020 and in that way technological progress in road transport will be stimulated. CO_2 emissions standards for trucks will do the same. International air transport will be included in the ETS. The remaining and difficult question is how to deal with the increasing volume of transport - number of cars and trucks and mileage. But the transport sector is so large that without a resolute policy approach no overall reduction target will be met whatsoever: there is no alternative. Therefore the real question is whether an overall cap might deliver reductions. These reductions will certainly be costly but the inherent boost to technology is also rewarding as has been demonstrated in the ECF analysis. In its Climate Change Act 2008 Impact Assessment, the UK government estimated the present value of total costs of the law to be 324-404 billion Pound over 43 years. The Best Estimate net benefit was 641 billion Pound in this period. As the ambition suggested in the Volume 1 analysis is -90% instead of -80% and includes only non-ETS sectors, the European figures will be different, but it might be expected that the relations are comparable. Two issues underline the uncertainty of the estimate: energy prices and the amount of international trade that is allowed in the system. With higher fossil fuel prices the relative costs of emission reduction decrease, with lower shares of international carbon trade they possibly increase, at least in the meantime. The latter is highly uncertain, however, as comparable reduction efforts to take place in other major economies are assumed. By imposing a higher share of realisation within Europe a higher share of benefits (jobs, technology) will remain within our continent as well.
- *Flexibility* has been touched upon already. In the UK Climate Law a certain maximum of all measures to be implemented outside the country has been included. In the ultimate *Roadmap 2050* target it is proposed that full implementation takes place in Europe, for the abovementioned reasons. For the intermediary steps a certain share of CDM or its successors might be allowed to decrease costs (in the UK modelling the cost decrease due to international trading was computed to be 10%). In the ECN proposal EU member states are free to decide how they will achieve the target. This has to be laid down in national Climate Laws, but each country can do it in their own way.
- *Enforcemen*t. Even if Climate Laws have been adopted in member states, will they be implemented? Which enforcement mechanisms exist? This is a serious issue. Even when overall benefits surpass costs, free-riding might be tempting. Two governance issues might be

considered. First, national governments are accountable to national parliaments. Second, a transparent process of reporting could be proposed in the European arena, in which progress will be discussed in the Council and European Parliament based upon a two-yearly report by the Commission. By rewarding, blaming and shaming peer pressure to establish can be expected (see also below).

The essence of the Directive is the ultimate target. Four specific issues have to be mentioned.

- *Effort sharing*. The 2020 targets differ considerably from country to country. The 2050 reduction target is -90% in non-ETS sectors and therefore the room for effort sharing in targets is limited. But a small degree of effort sharing in targets could take place and financial instruments might be part of that approach. After a decision on the principles of the Directive has been made, this has to be looked at.
- *Intermediary steps*. To be credible, intermediary steps have to be formulated. In case the ultimate target is -90%, a linear path could be - 20/25% in 2020, -45% in 2030, - 65/70% in 2030 (other paths are possible, but each of them is as debatable as the other). To attain some flexibility, a certain share of emission reduction with CDM projects in intermediary years could be considered.
- *Independent mechanisms*. The national approaches have to guarantee independent mechanisms to come up with proposals for new policies and verify that policies are consistent with the carbon budget. In the UK this task is implemented by an independent Climate Change Committee, whereas in other countries it might be other organisations, like authoritative research institutes. These independent mechanisms might propose even more ambitious intermediary targets or other intermediary steps, but in this proposal they are not allowed to decrease the target or change the ultimate target.
- *Enforcement*. The introduction of a national climate law in member states and therewith the ultimate target, is binding. As suggested, national governments might discuss the annual progress with national parliaments. The outcome of this debate will be sent to the European Commission parallel with statistical information according to a common format. Every two years the Commission could draft a report on overall progress and discuss this with the Council and European Parliament. In this way a balance between national and European responsibilities might be found.

8.5 Conclusion

It might be useful to consider a European Climate and Resource Directive obliging member states to introduce Climate Laws for non-ETS sectors. This Directive could be very general in nature, but lay down the binding target to reduce greenhouse gas emission in non-ETS sectors with 90% by 2050. This approach contributes to stability and consistency in energy/climate policies in member states. The approach might be comparable with the UK Climate Law which has introduced more certainty for investors and a completely different way of thinking: the new framework is that an emission reduction target is too important to be missed. Effort sharing, intermediate steps, ways to attain flexibility and enforcement are important elements to consider.

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Abbreviations

BEV	-	Battery Electric Vehicle
FCEV	-	Fuel Cell Electric Vehicle
HDV	-	Heavy-Duty Vehicle
HEV	-	Hybrid Electric Vehicle
ICE	-	Internal Combustion Engine
LDV	-	Light-Duty Vehicle
Mtoe	-	Million tonnes of oil-equivalent
PHEV	-	Plug-in Hybrid Electric Vehicle