Applying European emissions trading and renewable energy support mechanisms in the Greek electricity sector (ETRES)

Report for :

Task 1: "International developments in emissions trading and renewable energy support mechanisms"

Task 2: "Integration of ET in the Greek electricity sector"

June 2004

Overview

This report describes RAE's contribution towards the fulfillment of Tasks 1 and 2 of the ETRES project and is organised in three sections.

The first section highlights the European Emissions Trading Scheme (EU EATS) and aims to complement the report drawn by CRES as part of RAE's obligations under Task 1 of the project.

The second section focuses on the implementation of the EU EATS on the European electricity sector, presents the greenhouse gas emissions from electricity generation and addresses the implications from the implementation of the scheme.

The third section deals with the current status regarding Climate Change in Greece, the relevant policies, measures and projections and the implementation procedure of the EU trading scheme. An overview of the Greek Electricity Sector and its distinctive characteristics with regard to the implementation of the EU trading scheme is also provided and analysed.

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1. The EU Emissions Trading Scheme

The purpose of this section is to provide a general overview of the European Emissions Trading Scheme (ETS), as established by Directive 2003/87/EC of the European Parliament and of the Council of 13 October 2003. As a number of issues related to the ETS scheme have already been addressed in the document prepared by CRES, this section will discuss only briefly the main points of the directive. However, a more extended discussion on the functionality and the characteristics of the ETS and the National Allocation Plans is provided due to the dominant role that the Greek Electricity Sector is expected to play in the scheme.

1.1. Introduction to the EU Emissions Trading Scheme

It is well known that combating climate change is one of the main priorities of the European Union. On 31 May 2002, the EU ratified the Kyoto Protocol committing itself to reduce its Greenhouse Gases[1] (GHG) emissions by 8% from 1990 levels during the period 2008 to 2012. This target, shared between the Member States under a legally binding Burden-Sharing Agreement[2], sets individual emissions targets for each Member State. By the beginning of 2003, the ten new Member States had also ratified the Kyoto Protocol prior to their joining EU on May 2004.

Climate change is a priority within the EU Strategy for Sustainable Development and also one of the four priority areas under the Community's 6th Environmental Action Programme, which calls for full implementation of the Kyoto Protocol as a first step towards reaching a long-term target of 70% in emission cuts. However, the backbone of the Commission's effort to implement the Kyoto Protocol is the "European Climate Change Programme" (EECP), launched in March 2000 with objectives to identify and develop cost-effective measures towards the EU Kyoto target complementing the efforts of the Member States.

The findings of the Second ECCP Progress Report[3] issued in April 2003 suggest that plenty of cost-effective measures towards GHG reductions indeed exist.. In particular,

[1] According to the Kyoto Protocol the six gases mainly responsible for climate change are: carbon dioxide (CO_2), Methane (CH_4), Nitrous oxide (N_2O), Hydro fluorocarbons (HFCs), Per fluorocarbons (PFCs) and Sulphur hexafluoride (SF_6).
[2] Decision 2002/358/EC
[3] http://europa.eu.int/comm/environment/climat/eccp.htm

forty-two potential emission reduction measures at a cost of less than €20 per tonne of CO_2 equivalent have been identified with a total emission reduction potential of up to 700 million tonnes of CO_2 equivalent. Note that the emission reduction needed to meet the EU's Kyoto target is estimated at around 340 million tonnes of CO_2 equivalent[4].

As part of the EU efforts in combating climate change and reducing GHG emissions, the Council and the European Parliament have adopted several initiatives including the directives and additional legislation indicatively listed in Box 1. In this context, and in an effort to meet the Kyoto protocol targets in a cost-effective way, the European Parliament and the Council endorsed on July 2003 Directive 2003/87/EC "establishing a scheme for greenhouse gas emission allowance trading within the Community". The Directive was published in the Official Journal on 13 October 2003.

Box 1 : Additional directives and legislation with direct or indirect effect towards environmental protection and GHG emissions reductions (non exhaustive list)

- Directive 2004/8/EC on the promotion of cogeneration
- Directive 2003/30/EC on the promotion of the use of biofuels or other renewable fuels for transport
- Directive 2003/96/EC restructuring the Community framework for the taxation of energy products and electricity
- Directive 2003/54/EC concerning common rules for the internal market in electricity
- Directive 2003/55/EC concerning common rules for the internal market in natural gas
- Directive 2003/66/EC with regard to energy labelling
- Directive 2002/91/EC on the energy performance of buildings
- Directive 2001/77/EC on the promotion of electricity produced from renewable energy sources in the internal electricity market

EU emissions trading is due to start in 2005 and will cover all Member States of the enlarged European Union (EU-25). Note that the EU scheme will be the first multi-national emissions trading scheme in the world and is considered a forerunner of the international emissions trading scheme under the Kyoto Protocol. In particular, the scheme foresees two compliance periods: the first running from 1 January 2005 to 31 December 2007 with allowance allocation and trading restricted to CO_2 emissions and a second period running from 1 January 2008 to 31 December 2012. It is estimated in the first period some 6,000 installations of the EU-15 (12,000 of the EU-25) will be

[4] EU MEMO/03/154 of 23.7.2003 (http://europa.eu.int/rapid/pressReleasesAction.do?reference=MEMO/03/154&format=HTML&aged=1&language=EN&guiLanguage=en)

covered by the scheme. As set out in Annex I to the Directive, the activities covered by the Directive include:

(i) Combustion Installations (with a rated thermal input larger than 20MW), oil refineries and coke ovens
(ii) Production and processing of ferrous metals
(iii) Production of cement, glass, ceramics, bricks and tile
(iv) Pulp production including paper and board

CO_2 emissions from the activities of Annex I in EU-15 correspond to about 46% of the total CO_2 emissions.

An important addition to the EU emissions trading directive is the proposal COM(2003)403 (approved by the Parliament on 20 April 2004) “amending the Directive establishing a scheme for greenhouse gas emission allowance trading within the Community, in respect of the Kyoto Protocol's project mechanisms”. This proposal, allows European companies to convert credits earned under the flexibility mechanisms "Joint Implementation" and "Clean Development Mechanism" envisaged by the Kyoto Protocol into emissions allowances under the EU ETS. The aim of these mechanisms is to reach the global emissions reduction targets in a cost-effective way while transferring advanced technology to other industrialised and developing countries.

In the new carbon-constrained economy of the 21st century, Europe takes the lead by adopting the instrument of emissions allowances trading. This initiative not only demonstrates its determination to tackle climate change seriously and now, it is also providing Europe with the major advantage of being the first to be exposed to this valuable learning exercise.

1.2. National Allocation Plans and Allocation of Allowances

One of the core tasks in the run-up to the implementation of the EU-wide greenhouse gas allowance trading scheme is the elaboration of the National Allocation Plans (NAP) by each Member State. Allocation is governed by Articles 9 to 11 and Annex III of Directive 2003/87/EC and must be based on objective and transparent criteria. In detail allowance allocation under a Member State’s NAP:

- must be consistent with the Member State’s Kyoto targets taking into account the actual and projected progress towards fulfilling these targets

- must be consistent with the potential of activities covered by the scheme to reduce emissions
- must be consistent with other Community legislative and policy instruments
- must not discriminate between companies or sectors
- must contain information on how new entrants, early action and clean technologies are taken into account
- must take into account comments expressed by the public
- may take into account competition from countries or entities outside the EU

In order to assist the Member States in the implementation of these criteria, the Commission has issued a relevant guidance (COM(2003) 830, 07.01.2004). Even before the final version of the Directive was agreed, the Commission had produced a non-paper as a guide on developing a NAP[5].

In particular, in order to determine the amount of allowances to allocate to the installations covered by the scheme, Governments first have to work out how much of their Kyoto objective for the 2008-2012 period should be achieved in the 2005-2007 period. Emissions projections based on energy policies, prices and expected GDP growth have to be taken into account.

The next step is to determine how to allocate allowances between sectors covered by the scheme and those that do not, and finally how to allocate allowances among sectors participating in the scheme. For each sector, estimated growth rates and the potential to reduce emissions have to be taken into account. Intense industry lobbying is expected over this level of allocation.

Once the total and sectoral caps have been decided, then the allowances for individual installations covered by the scheme are determined. Allocation at this level is usually determined based on historic emissions during a base period, with possible adjustments rewarding early action or clean technology. A correction factor is applied so that aggregate allowances are equal to the sectoral constraint. Determination of the base period is flexible to allow for data availability, anomalous years, major repairs etc.

Another option for determining installation-level allocation is benchmarking that takes account of best practice standards and/or projected production. The underlying

[5] EC (2003a)

principle of benchmarking is to grant allowances on the basis of a specific emission factor per unit of output. However, benchmark allocation makes stringent demands on data and needs extensive preparatory work to determine the right benchmarks and therefore is not expected to be applied for the first compliance period. Allocation to new entrants is expected to be based on some form of benchmarking.

The delay exhibited by most Member States to comply with the timetable set by the Directive clearly depicts the difficulty in developing a NAP acceptable by all parties involved and in the path to meet the Kyoto targets of the Member State.

In detail, according to the ET Directive, all Member States of EU-15 had to submit their NAPs by 31 March 2004. For the new Member States of EU-25 the respective deadline was the 10st of May 2004. However, the first deadline was met only by eight Member States of EU-15. Table 1 summarises the progress made so far (24.06.2004) in the publication of NAPs showing that 15 out of 25 Member States have submitted a complete NAP for approval to the EU, 5 States have published NAPS in preliminary or draft form whereas 3 States, including Greece have not yet completed their allocation plan. Cyprus and Malta are not required to submit an allocation plan. According to the Directive, the Commission has three months after the NAP submission to accept, reject or request that amendments are made to the original plan. Box 2 illustrates the timeline of decisions and events for the implementation of the EU ETS.

Table 1: Status of the allocation process

Countries with published NAPs until June 2004	Countries with NAPs in Draft form	Yet to publish
Germany, Finland, Ireland, Denmark, Austria, Luxembourg, The Netherlands, Sweden, Slovenia, Lithuania, United Kingdom, Slovak Republic, Estonia, Latvia and Portugal	Belgium, France, Italy, Czech Republic, Hungary (principles only)	Greece, Poland, Spain

Box 2: Timeline of Decisions and Events for the EU ETS

Summer 2003	Entry into force of EU ETS Directive
End of 2003	Transposition into national law
06.01.2004	Adoption of NAP guidelines
31.03.2004	Deadline for the current EU-15 Member States to submit their NAPS to the Commission
10.5.2004	Deadline for the ten accession countries to submit their NAPs to the Commission
31.5.2004	The Commission gas to approve NAP submissions from accession countries

31.06.2004	Within 3 months of a Member State submitting its NAP, the Commission must address whether the NAP is in keeping with the guidelines. The Commission may reject the whole or part of the NAP
30.09.2004	Member States have to publish their National Allocation Plans, National Registries must be established by September
01.01.2005	Start of the first phase of the EU ETS
28.02.2005 (annually)	Deadline for Allocation of EU Allowances for the current calendar year
31.12.2005 (annually)	End of the compliance year
31.03.2006 (annually)	Installations report 2005 emissions
30.06.2006	Commission required to report to the European Parliament and Council on the progress of the first phase of the scheme and may suggest extending the scheme to new industry sectors and/or additional greenhouse gases
30.06.2006	Member States submit their NAP for the second phase of the scheme
01.01.2007	Deadline for Member States to adopt the NAP for the second phase of the emissions trading scheme, running from 2008-2012
01.01.2008	Start of the second phase of the EU ETS

1.3. Economic implications of the Scheme

The ETS adds a carbon constraint in the EU economy as industries covered by the scheme face opportunity costs reflected in the allowance price. The past three months, prices of Phase 1 allowances are in the region of 7-10 €/tCO_2, although this value is based on very few trades[6]. These prices are expected to change markedly as the market develops and are likely to depend on a number of factors such as economic growth, the allocation and total amount of allowances issued under the scheme and the extent to which countries will use the Kyoto flexibility mechanisms to meet their targets following the linking of JI and CDM-generated credits with the emissions trading scheme. This linking could lead to a reduction in the overall compliance cost by as high as 60%[7]. In general terms, if allowances are allocated according to business as usual (BAU) tendencies, their price is expected to be low in the initial phase of trading. In this case, any country that will require emissions reductions greater than the BAU

[6] www.pointcarbon.com
[7] KPI technical report, 2003.

scenario may see a benefit in the form of low-cost early compliance during the first phase.

Competitive distortions could arise as a result of the EU ETS since each Member State implements its own NAP with varying assumptions and methodologies. Given the tight margins in some industries, a company or a sector with tougher allocation would be placed at a competitive disadvantage relative to a respective company or sector in a country with more lenient allocations. In order to limit the impacts on competitiveness, countries may choose to adjust the allowances allocation away from sectors that do not face international competition. From an EU-wide perspective, there is a concern that energy-intensive industries may be driven out of Europe.

Another implication of the scheme' implementation at the EU-level is that the expected trend away from coal towards more carbon-efficient but mainly imported natural gas, will increase EU's energy import dependence to levels that might be a source of concern.

1.4. Highlights on the functionality and implementation of the EU ETS

Every year, each installation covered by the scheme must monitor and measure or calculate its emissions for that calendar year according to the guidelines set out in the Commission's Decision COM(2004)130. If its emissions are less than the amount of allowances it has been allocated, it can either sell the excess allowances or bank them for future use, if the Member State's NAP allows so. If its emissions are above its allocated allowances, it must purchase allowances from the market to cover the difference. By 30 April of the following year, the installation's operator has to submit to the Competent Authority a number of allowances equal to the number of CO_2 tonnes emitted during the year. Failure to do so results in a penalty of 40 €/tCO_2 in the first period (100 €/tCO_2 in the second period) and also in the requirement to surrender that additional amount of allowances the following year.

The economic rationale behind Emissions Allowances Trading is that in a well-functioning and competitive market, allowances will end up distributed among installations that value them most, in a way that minimises the total cost of reducing emissions: if an installation's marginal cost to reduce emissions at the source is lower than the market price of the emission allowance, the installation will choose to reduce its emissions further and sell the allowances that are freed up by doing so. If its marginal cost is higher than the market price, the installation will choose to maintain its emissions or even increase them by buying extra allowances on the market. The limit set on total emissions guarantees the environmental efficiency.

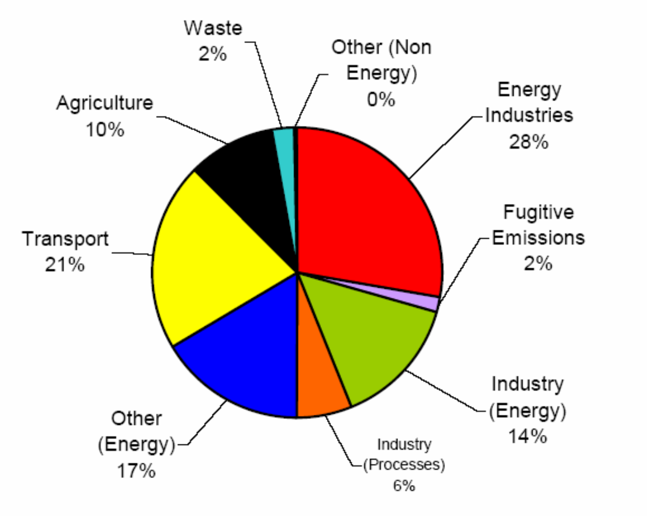
The Directive provides the opportunity to operators of installations covered by the scheme to form “pools” of installations from the same activity for the purposes of participating in and complying with the scheme in the first and/or the second compliance period, if the Competent Authority and the NAP allows them to do so. Operators wishing and allowed to form such a pool will nominate a trustee who will be issued with the total quantity of allowances calculated by installation and will be responsible for surrendering allowances equal to the total emissions from the installations in the pool. Pooling could make the management of allowances and monitoring of emissions easier and reduce the administrative tasks and transaction charges associated with allowance exchanges between installations that are owned by the same company. The Commission may reject an application for pooling if the pooling system is not transparent or if the pool is too large as this would limit the liquidity of the market.

2. The Electricity Sector in the EATS

2.1. Emissions

Energy Industries (mainly electricity and heat production but also petroleum refining and manufacture of solid fuels) are the most important source of CO_2 emissions in the EU, accounting for 28% of total in 2001[8]. According to the European Environmental Agency, the EATS could cover up to 940 million tonnes of CO_2 equivalent ($MtCO_2e$) emissions from the power and heat sector in the EU-15. Including also emissions from the power and heat sectors in the new 10 EU members brings the total coverage up to about 1200 $MtCO_2e$. To illustrate the magnitude of the scheme, consider[9] that for a carbon price of € 7/tCO_2, the total value of allowances (assets) to be managed by the European power and heat industries can be of the order of € 8.4 billion per annum, or € 26.2 billion for the period 2005-2007.

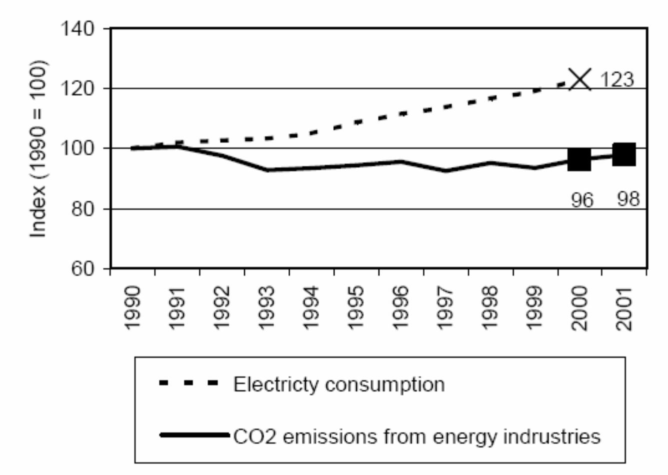
Figure 1: Sectoral breakdown of EU-15 GHG emissions in 2001. Source: EEA 2003.



Between 1990 and 2001, CO_2 emissions from energy industries in the EU fell by 2% while final electricity consumption increased by 23% (see Figure 2). This was mainly due to fuel shifts in power production from coal to natural gas, larger shares of generation from renewable energy sources and nuclear power as well as from efficiency improvements.

[8] EEA 2003
[9] Point Carbon (http://www.pointcarbon.com/category.php?categoryID=125#consequences)

Figure 2: EU CO2 emissions from energy industries compared with electricity production



It is important to note that emissions from the transport sector which is not covered by the EU ETS, constitute a significant share of total CO_2 emissions (21% in 2001). According to the European Union Energy Outlook to 2020, under baseline assumptions (no additional measures) CO_2 emissions from the transport sector in 2020 will be 40.6% higher than 1990 levels and the sector's share of total emissions will rise to 29.6%.

Table 2: CO_2 emissions index by sector (1990=100). Source Capros et al 1999.

	1990	1995	2010	2020
Industry	100	88.8	88.3	82.7
Tertiary	100	105.2	114.3	105.1
Households	100	95.4	99.2	100.2
Transports	100	108.9	135.4	140.6
Electricity & Steam Production	100	95.8	99.2	117.1
TOTAL	100	98.7	107.1	114.0

The above imply that strong measures, possibly including an increase in fuel tax, should be required in order for the sector to contribute to the overall required emissions reductions.

2.2. Implications

The electricity generating sector is likely to carry most of the burden of CO_2 emissions reductions because it faces limited international competition and also has a relatively large scope for low cost abatement in terms of fuel switching and efficiency improvements. This is reflected in the NAPs that have already been submitted where most of the emissions reductions are required from the electricity generation sector.

Fundamental implications for the electricity sector are expected as a result of the implementation of the EATS such as:

- Switching to more carbon-efficient forms of generation as they become more competitive.
- Higher wholesale) prices due to increased production costs.
- New cost/revenue streams from trading allowances.

The parts of the sector that are not covered by the scheme, like renewable energy and nuclear power, will gain some competitive advantage relative to fossil fuel generators, to the extent that electricity prices -and therefore their profits as non-carbon generators - will rise.

Implementation of the scheme is not expected to have significant competitive distortions for the electricity sector at the national level (other than through an expected slight decrease in demand) as transmission capacity constraints limit competition from other countries.

However, as the scheme is expected to enhance the trend towards gas-fired generation, issues of security of energy supply for the EU will arise.

2.2.1. Increased costs and prices

In the new carbon-constrained market, the competitiveness of carbon-intensive generation which produces more CO_2 emissions per unit of output (eg from coal) will decrease relative to more carbon-efficient generation (eg from natural gas). The value of CO_2 as an opportunity cost (the revenue from selling the allowance) should be included in the cost structure of generation in the same way as fuel costs are.

Assuming a CCGT plant with a carbon intensity factor of 0.37 tCO_2/MWh (corresponding to thermal efficiency of 50%) and a Pulverised Coal plant with a carbon intensity factor of 0.90 tCO_2/MWh (corresponding to thermal efficiency of 36%), the following table shows the impact of different carbon prices to the plants' marginal production costs:

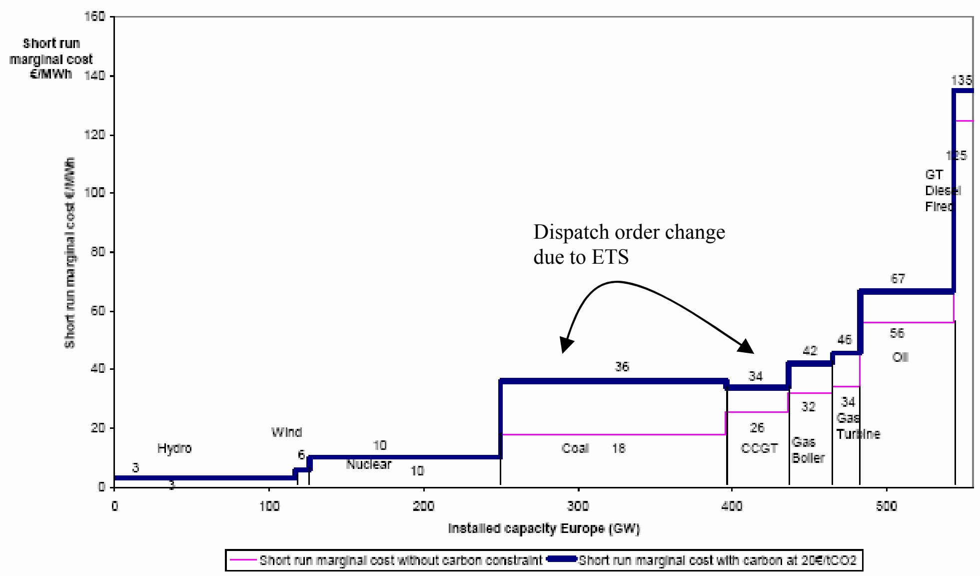
Table 3: Indicative impact of allowance price to marginal generation cost

Allowance price (€/tCO_2)	Cost impact (€/MWh) by technology	
	Coal-fired	**CCGT**
5	4.5	2.2
10	9.0	4.3
15	13.5	6.5
20	18.0	8.6

The effect of a 20 €/MtCO_2 allowance price on the short-run marginal cost of electricity production and the merit order of power plants is shown in Figure 3. As demonstrated, the introduction of the allowance price in the cost structure would change the plant dispatch order with CCGT plants displacing coal-fired ones.

The wholesale price of electricity is determined by the most expensive resource called upon to meet demand (the system marginal price), typically a thermal power station. An increase in the production costs of the thermal plants is likely to increase the wholesale price of electricity. Of course, the effect on the retail price will be much lower since transmission, distribution and administrative costs as well as taxes are included in the final price.

Figure 3: Impact of a 20 €/MtCO_2 allowance price on the plant merit order. Source: IEA 2003



Potential increases in the electricity price are likely to have significant implications for the electricity-intensive industries by increasing their production costs and placing them at a disadvantage relative to international competition.

2.3. Specific issues concerning the implementation of the EU EATS in the electricity sector

As mentioned above, the electricity sector will play a dominant role in the EU EATS. This section provides an overview of the elaboration process of the National Allocation Plan with regard to the electricity sector.

2.3.1. Choosing the most appropriate Baseline period

Electricity demand is correlated to weather conditions that can vary from year to year (a dry year limits the usage of Hydro plants, a hot year increases demand for air-conditioning etc). Therefore a multi-year baseline for determining allowances allocation has to be chosen in order to mitigate possible fluctuations in emissions due to such factors. A 3 to 5 year period should give a good average. A significantly anomalous year could be omitted.

Because of the large number of installations covered by the scheme, data availability from all installations and for all base-period years has to be ensured. For installations beginning operation within the base period, allocation should be based on available data and if they are not sufficient, pro-rata projection or benchmarking could be used.

Also significant production switching between installations during the base period should be taken into account.

2.3.2. New Entrants

New entrants (NE) are installations that are commissioned or have their capacity expanded from 1 January 2005 onwards[10].

The Commission recommends that a Reserve of allowances is set aside for NE and this is the approach is already adopted in the NAPs submitted so far to the Commission for review. The reserve is calculated to ensure that an adequate quantity of allowances is available for all expected NE that underlies the electricity sector's growth rate. Left over allowances can be canceled, auctioned or re-entered to the sectoral allocation. If new investment is more dynamic than anticipated, the NE operators will have to buy allowances from the market. The amount of allowances set aside for NE can be refined using information on the expected split of growth between new entrants and existing installations.

The quantity of allowances allocated to each NE installation can be calculated as the product of installation capacity, projected average utilisation (subject to ex post adjustment), electricity generation benchmark (derived from a BAT-based specific emission value) and the ratio of time from commissioning until end of compliance period to full duration of period.

Benchmarks are designed to encourage competition in the electricity generation process with the best CO_2 performance. The benchmark value is derived from the weighted average of emissions in generation from lignite, coal and gas in the generation system. The benchmark value will be at least that of a modern CCGT plant.

2.3.3. Closing of installations

If an installation is permanently ceases operation during the compliance period[11], the Competent Authority will cancel its GHG emissions permit and all allowances not submitted to the Authority can be either transferred to the New Entrants reserve or auctioned or even cancelled. The operator of an installation that shuts down may choose to transfer the remaining allowances to a new entrant, but the receiving installation will not qualify for “new entrant” treatment.

In order to overcome complications that may arise from closing of installations, some countries have chosen to issue allowances annually rather than once for the entire period.

2.3.4. Early action

The Commission considers “desirable from a fairness point of view” the special treatment of early action but leaves to each Member State how to define and whether and how to accommodate early action. Generally, existing installations can qualify for

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[10] For installations commissioned after the end of the base period, but before 1 January 2005, the allocation could be based on average annual emissions if data are available or reported emissions subject to ex-post adjustment after verification.

special "early action" treatment if they can demonstrate a reduction in CO_2 emissions (relevant to year of commissioning) before the publication of the NAP, provided that these reductions were not achieved simply by decommissioning plant and/or a decline in output, or as a result of public funding or legal requirements.

The Commission suggests that early action treatment can be accommodated by three possible methods: by choosing an early baseline period, by setting aside a bonus reserve of allowances for installations that have undertaken early action or by using benchmarks to reward the more carbon efficient installations.

2.3.5. CHP generation

Combined Heat & Power (CHP) installations have a particular role to play in CO_2 emissions reductions for reasons of both cost structure and reduction potential. The EU is committed to the support of CHP and Directive 2004/8/EC on the promotion of cogeneration aims to increase the share of CHP generation from 10% of all electricity consumption in EU in 2000 to 18% by 2010.

The specific problem with CHP generation with regard to the EU ETS is that despite the increasing efficiency, CO_2 emissions are higher when power and heat are produced together compared to sole power generation. Without a special treatment of new CHP plants, a negative incentive to further uptake of CHP should be expected.

According to the NAPs submitted to date, different approaches for treating new CHP plants have been proposed:

- allow transfer of allowances from installations that close (Germany)
- supplementary bonus allocation (Czech, Slovenia, Germany)
- reduction of emission cuts requested compared to the rest of the sector (Austria)
- benchmarking (Netherlands, Germany, Ireland)

2.3.6. Flue Gas Desulphurisation

FGD is equipment that removes approximately 90% of SO2 emissions from processes that use fuel containing sulphur (mainly coal or oil-fired power stations).

[11] De facto termination can be declared if the installation emits in a year eg less than 10% of its average baseline emissions.

Limits on SO2 emissions are expected to tighten over the years ahead due to EU regulations such as Directives 1999/30/EC, 96/92/EC, 2001/77/EC and 2001/81/EC.

The FGD equipment itself uses some energy. Consequently, a plant with FGD produces about 3% higher carbon emissions and as a result installations that fit FGD after the baseline period will receive fewer allowances than needed (based on lower emissions per unit of output). Moreover, due to the tightening limits on SO2 emissions, it is likely that in the future greater use of FGD-equipped plants will be made at the expense of similar plants without FGD. Consequently, an installation that fitted FGD after the baseline period will find its load factor and therefore its emissions increased further in relation to those in the baseline period. It has been suggested that the allowances allocated to such installations should be increased at the expense of similar plants without FGD.

3. The Greek electricity sector in the EU ETS

3.1. Steps towards the implementation of the ET Directive in Greece

3.1.1. Greece and Climate Change

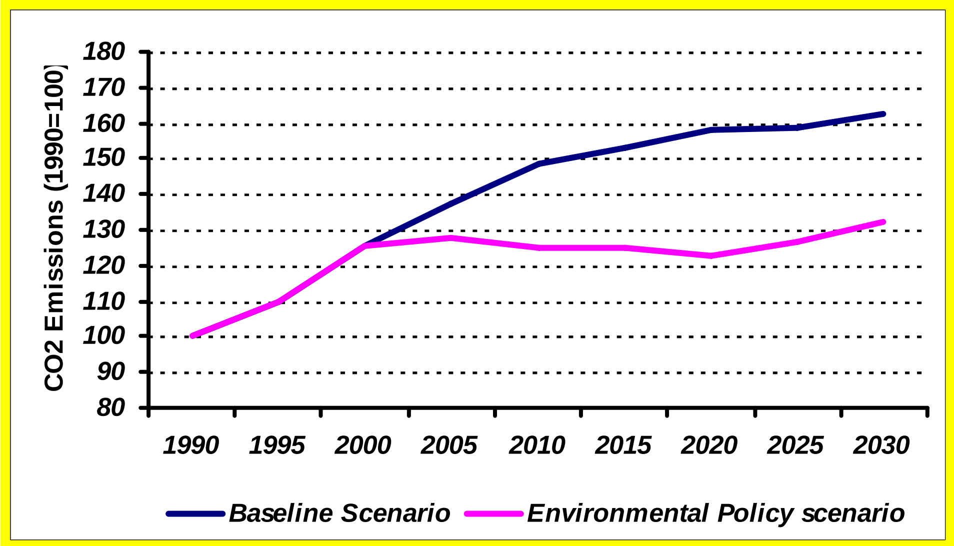
Under the EU burden-sharing agreement, Greece has to limit the net increase of its GHG emissions by 2008-2012 to 25% above 1990 levels. Provisional figures for 2002 show already a 20.0% increase of GHG emissions compared with the base year[12]. However, the projected path of GHG emissions in Greece is well above the required path to meet the Kyoto targets, as shown in Figure 4.

On January 2003, RAE issued the report “Long-Term Energy Planning for Greece, for the period 2001-2003”. This report presented a quantitative analysis for the Greek Energy Sectors using three different scenarios: A **“Baseline”** scenario that assumes that the observed trends and the policy measures already in place will continue but with no additional measures; an **“Environmental Policy”** scenario that assumes that the Kyoto target for Greece is reached with additional domestic measures and a **“Negative Developments”** scenario.

Figure 4 illustrates the historical data of CO_2 emissions for the period 1990-2000 and the projected paths under the Baseline and the Environmental Policy scenarios. (Kyoto target = 125)

[12] NOA 2004a

Figure 4: Evolution and projections of CO2 emissions in Greece under the Baseline and the Environmental Policy scenarios. Source: RAE 2003.



Lack of comparative analysis of the cost-effectiveness of the different measures in the various sectors has made unclear what the total cost of compliance to the Kyoto target will be and whether the least-cost measures are being pursued.

The challenging target makes it likely that Greece will make use of The Kyoto flexibility mechanisms (IET, JI and CDM) in order to meet the target.

The electricity generation sector is the major CO_2 emitter in Greece with 55MtCO_2 or 52.7% of total CO_2 emissions. This is illustrated in Figures 5 and 6.

Figure 5: Sectoral breakdown of CO2 emissions in Greece in 2002. Source NOA 2004

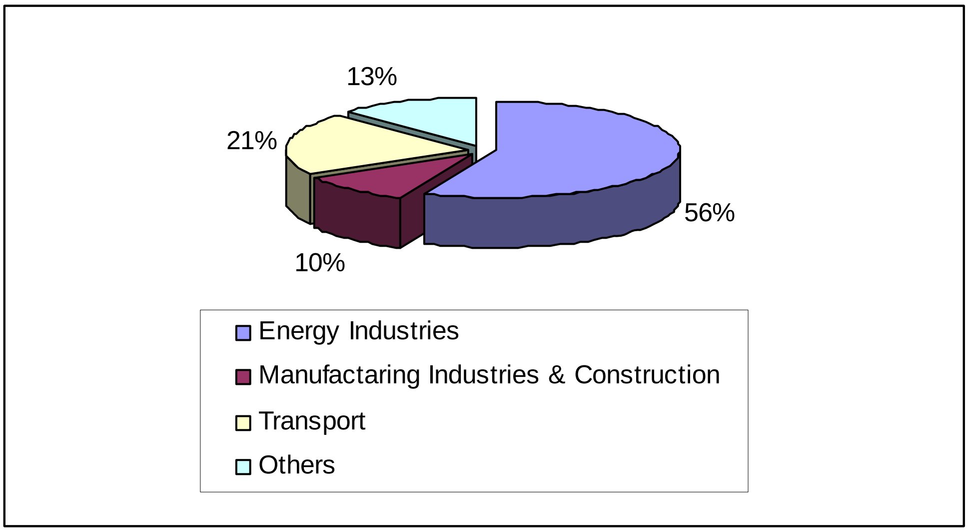
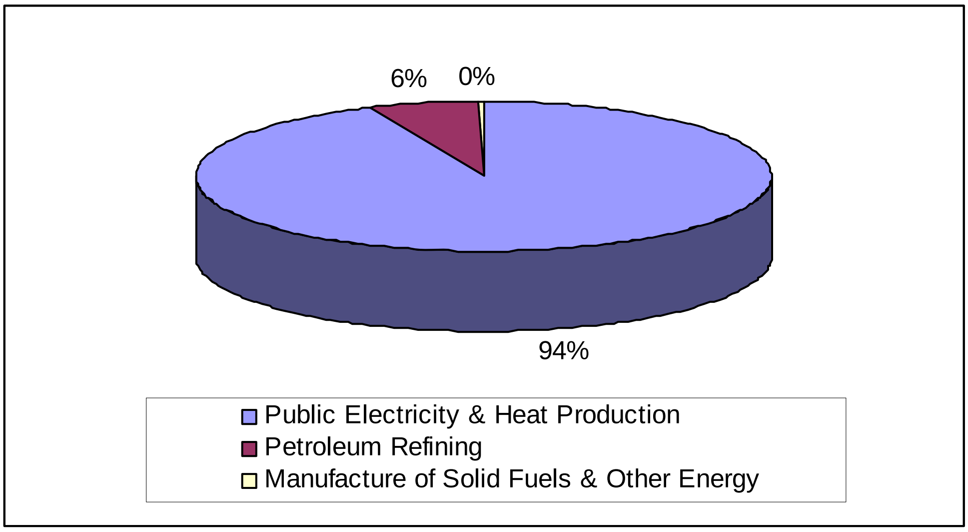


Figure 6: Energy Industries' CO2 emissions by activity in Greece in 2002. Source: NOA 2004



The projected CO_2 emissions by sector under the Environmental Policy scenario and the changes relative to the Baseline scenario are shown in Table 4.

Table 4: CO_2 emissions by sector under the Environmental Policy scenario and changes relative to the Baseline scenario

CO2 Emissions by sector (Mt)	**2000**	**2005**	**2010**	**2015**	**2020**	**2025**	**2030**
Industry	10.09	10.81	10.83	10.83	10.92	11.29	11.61
	0.0%	-5.8%	-8.9%	-11.6%	-11.0%	-9.7%	-10.0%
Tertiary Sector	3.35	3.52	4.13	4.33	4.97	5.28	5.64
	0.0%	-8.9%	-11.0%	-13.6%	-12.0%	-9.6%	-10.4%
Domestic Sector	7.43	5.76	6.08	6.53	6.57	6.63	6.58
	0.0%	-8.5%	-10.0%	-11.2%	-15.9%	-12.0%	-11.3%
Transports	21.24	23.63	24.32	24.85	25.71	26.39	27.34
	0.0%	-3.6%	-7.0%	-10.4%	-12.2%	-12.0%	-8.5%
Electricity & Heat production	43.63	43.90	40.09	39.01	35.67	36.66	39.19
	0.0%	-9.2%	-23.8%	-26.3%	-33.2%	-30.8%	-28.8%
Other Energy Industries	3.41	3.24	3.38	3.48	3.55	3.64	3.73
	0.0%	-2.4%	-3.3%	-4.8%	-5.8%	-5.3%	-3.6%
Total	**89.16**	**90.86**	**88.85**	**89.03**	**87.43**	**89.92**	**94.13**
	0.0%	**-7.1%**	**-15.9%**	**-18.3%**	**-22.1%**	**-20.2%**	**-18.4%**

It is important to note that the Transport sector that is not covered by the EU ETS, currently accounts for 21% of Greece's total CO_2 emissions and according to the Environmental Policy scenario is required to reduce its emissions by 7.0% by 2010 relative to the Baseline scenario. Due to the sector's inelastic short-term demand, strong measures, possibly including an increase in fuel tax, should be required if the sector's estimated emissions reductions share is to be met.

Note that, on 05.03.2003 (ΦΕΚ 58/5) Greece published the GHG Emissions Reductions National Programme for 2000-2010, providing a blueprint for the country to meet its Kyoto Protocol obligations. The policies and measures contained in this document have begun to be implemented but much work remains for the targets to be met.

3.1.2. EATS & NAP production in Greece

According to article 31 of the EU ETS Directive and the respective timetable outlined in Box 2, Member States had to bring into force all laws, regulations and administrative provisions necessary to comply with this Directive by 31 December 2003 at the latest.

For this purpose and in order to comply with the requirements of the EU ETS Directive, the Ministry of Environment, the authority mainly responsible for the implementation of the national Climate Change Program, invited on 14.10.2003, (just one day after the publication of the Directive to the EU Official Journal), the Ministry of Development in order to form a joint Working Group. Steps towards the implementation of the Directive in the national legislation commenced on December 2003 but were interrupted in February 2004 due to the General elections on early March. Works resumed in April 2004 and a draft proposal incorporating the EU ETS Directive into national legislation is estimated to be completed by the end of July.

Unfortunately, similar delays in the preparation of the Greek National Allocation Plan are also depicted. On 28 July 2003, the Minister of Development announced his intention to award a contract under the open procedure for procurement of services towards the design of a data base of GHG emissions and the development of a National Allocation Plan. In detail the call was aiming to select consultants to:

- evaluate alternative initial allocation mechanisms with particular reference to the Greek market
- propose a National Allocation Plan
- set up a database system to include all installations covered by Annex I to the Directive
- design and implement the National Registry as defined by Article 19 of the Directive.

The deadline for interested parties to submit their proposals expired on 23rd September 2003. A preliminary decision was reached on 20 January 2004. Finalization of the contract award and completion of the Greek NAP are still pending. Submission of the Greek NAP to the Commission for evaluation is not expected before the end of August 2004.

Up to now (June 2004), RAE has not been engaged in the national preparation for implementation of the ETS trading scheme.

3.2. The Greek Electricity Sector

3.2.1. Market structure – Regulatory overview

Market reform of the electricity sector begun with the Law 2773/99 which was adopted in order to comply with the EU Directive 96/92 concerning common rules for the internal market for electricity.

An independent **Regulatory Authority for Energy** (RAE) was put in place. Its role is to facilitate competition in the energy sector, to secure the national energy strategy in the liberalised market context in a cost-effective and environment-friendly manner while protecting the consumers and to guarantee security of supply. RAE overviews and monitors the energy markets, provides opinion to the Minister of Development for regulations (Grid Code, Power Exchange Code), for transmission access and captive consumer tariffs and for Generation and Supply Licenses.

The Ministry of Development has the primary regulatory responsibility and is not bound to follow RAE's opinions and recommendations. Greece is the only country in the EU where the regulator has not decisive responsibilities in the electricity sector. However, RAE has decisive powers on imposing sanctions on the market participants.

In addition, an independent **Hellenic Transmission System Operator** (HTSO) was established to operate and administer the mainland's High Voltage transmission lines and to guarantee non-discriminatory access to the System for any eligible party.

3.2.2. Electricity generation

In 2003 the total installed electric power generation capacity in Greece amounted to 12,697 MW, increased by 3.6% from 2002 levels[13]. Out of the total installed capacity, 88% is on the mainland whereas 12% is distributed on the non-interconnected islands[14].

Table 5 shows the installed generation capacity by technology and the annual change for the years 2000 to 2003.

In 2003 net electricity production was 54.4 TWh increasing by 7.5% from 2002 while net imports were 2.1 TWh, 27.6% down from 2002 levels.

Figure 8 shows the increase in electricity generation for the period 1971-2001 and its breakdown by fuel type clearly indicating the gradual penetration of natural gas during the past 5 years.

3.2.3. Future projections

During the 90's electricity demand in Greece increased with an average annual rate of 4.8%. According to RAE's report "Long-term Energy planning for Greece for the Period 2000-2010", electricity demand will increase in that period with an average annual rate of 4%.

Figure 9 shows the projected increase in electricity demand and production, and the projected increase of installed capacity and peak load, compared to 1995 levels under the Baseline Scenario in this report.

Table 6 illustrates the projected contribution to electricity generation by plant type to 2030 under the Baseline and the Environmental Policy scenarios. It is evident that Renewable Energy Sources other than large-scale hydro plants should have a significant contribution (6.9% of electricity produced in 2010 compared to 2.9% under the baseline scenario) for the Kyoto target to be met.

3.2.4. New generating capacity in the short-term

With the exception of Renewable energy sources and small scale CHP that have a special treatment with investment cost subsidies and/or a feed-in tariff system, the electricity generation sector in Greece has not developed as was initially envisaged.

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[13] RAE 2004

[14] See section 3.3.4 for details.

Although Generation Licenses totaling 4,400 MW for new large-scale CCGT plants (400MW to the incumbent PPC) have been issued since 2001, only one 390MW plant is expected to start operation by 2007. Table 7 summarises the latest and expected new thermal generation capacity in mainland Greece

Figure 7: Installed generation capacity by primary energy source for mainland Greece.

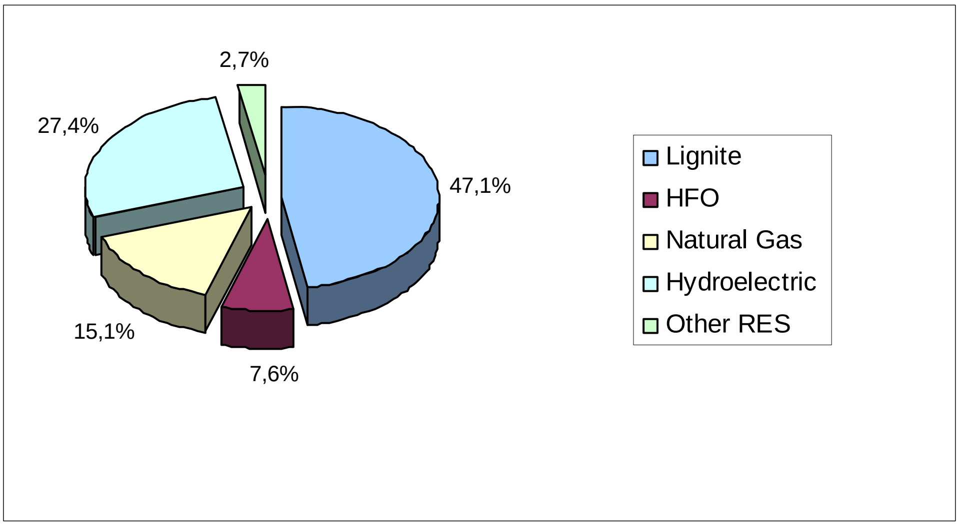


Table 5: Evolution of installed generation capacity in Greece by technology

	INSTALLED CAPACITY (MW)				annual % change		
Year	2000	2001	2002	2003	01/00	02/01	03/02
Mainland and Interconnected Islands							
Thermal Power Plants							
Coal	4908	4933	4958	5288	0.51	0.51	6.66
HFO	777	771	858	858	-0.72	11.20	0.00
Natural Gas	1100	1103	1693	1693	0.25	53.54	0.00
Total Thermal	**6785**	**6807**	**7509**	**7839**	**0.33**	**10.31**	**4.39**
Hydroelectric Plants							
small (1-10 MW)	24	31	35	38	29.17	12.90	8.57
large (>10 MW)	3039	3039	3039	3039	0.00	0.00	0.00
Hydroelectric	**3063**	**3070**	**3074**	**3077**	**0.23**	**0.13**	**0.10**
Other RES	**137**	**199**	**217**	**308**	**45.65**	**8.58**	**42.40**
Total	**9985**	**10077**	**10799**	**11224**	**0.92**	**7.17**	**3.93**
Non Interconnected Islands							
Thermal Power Plants							
Coal	-	-	-	-	-	-	-
HFO & LFO	1290.0	1315.0	1365.0	1365.0	1.94	3.80	
Natural Gas	-	-	-	-	-	-	-
Total Thermal	**1290.0**	**1315.0**	**1365.0**	**1365.0**	**1.94**	**3.80**	**0.00**
Hydroelectric Plants							
small (1-10 MW)	0.3	0.3	0.3	0.3	0.00	0.00	0.00
large (>10 MW)	-	-	-	-	-	-	-
Hydroelectric	**0.3**	**0.3**	**0.3**	**0.3**	**0.00**	**0.00**	**0.00**
Other RES	**76.3**	**78.8**	**83.0**	**107.1**	**3.28**	**5.33**	**29.04**
Total	**1366.6**	**1394.1**	**1448.3**	**1472.4**	**2.01**	**3.89**	**1.66**
TOTAL	**11351.5**	**11470.6**	**12247.7**	**12696.6**	**1.05**	**6.77**	**3.67**

Figure 8: Evolution of electricity generation by fuel (1971-2001). Source: IEA Energy Statistics

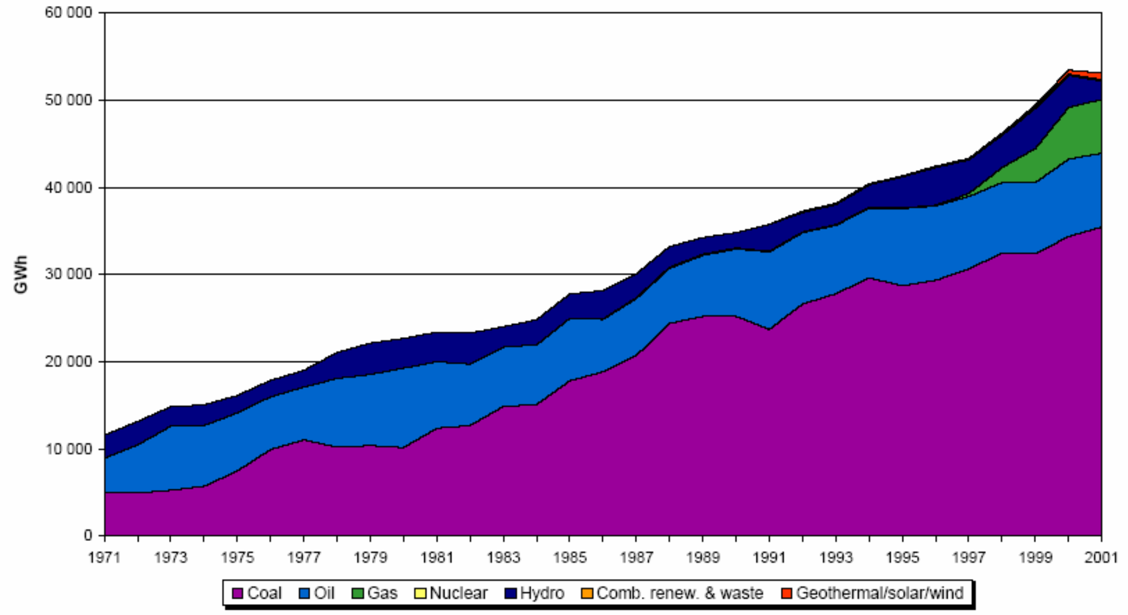


Figure 9: Projections of electricity demand and production, installed capacity and peak load for Greece, 1995-2030. Source: RAE 2003a

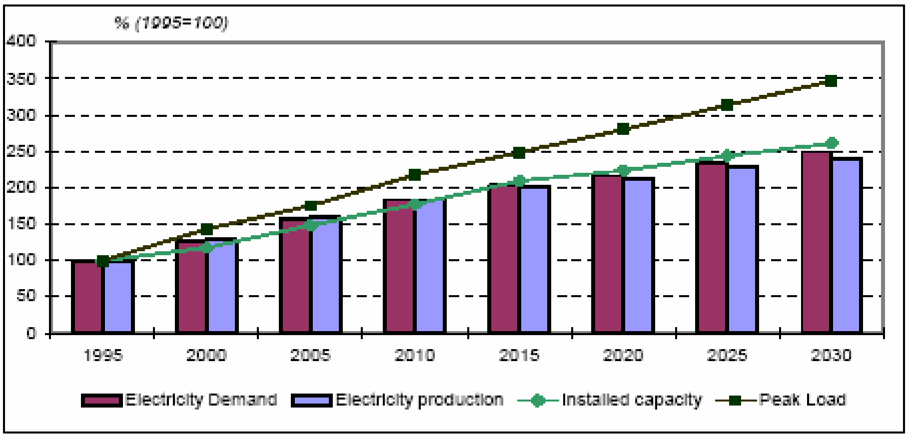


Table 6: Projected contribution to electricity generation by plant type under the Baseline and the Environmental Policy scenarios. Source: RAE 2003a.

Contribution to electricity generation by plant type (%)								
	1995	2000	2005	2010	2015	2020	2025	2030
Baseline scenario								
RES	**8.6**	**7.8**	**10.8**	**10.4**	**11.2**	**11.2**	**11.8**	**12.4**
Small hydro, wind turbines, other RES	0.1	0.9	2.8	2.9	5.0	5.3	5.6	6.6
Large Hydro	8.5	6.9	8.0	7.5	6.2	5.9	6.2	5.9
Thermal plants	**91.4**	**92.2**	**89.2**	**89.6**	**88.8**	**88.8**	**88.2**	**87.6**
Environmental Policy scenario								
RES	**8.6**	**7.8**	**13.4**	**15.9**	**15.4**	**15.3**	**14.1**	**14.8**
Small hydro, wind turbines, other RES	0.1	0.9	4.8	6.9	7.6	8.0	7.4	8.5
Large Hydro	8.5	6.9	8.6	9.0	7.7	7.2	6.7	6.3
Thermal plants	**91.4**	**92.2**	**86.6**	**84.1**	**84.6**	**84.7**	**85.9**	**85.2**

Table 7: Thermal plants in operation after 2002, under construction and licensed, by technology.

Technology/Fuel	**In operation after 2002 (MW)**	**Under construction (MW)**	**Licensed (MW)**
Steam / Lignite	330		
CCGT / NG	480	390	4023
CHP / NG & Oil	183	167	218
Other NG-fired		120	140

The main reasons for the lack of investor interest for new generating capacity in Greece have to do with increased business risk and the associated unwillingness of the financial markets to fund these projects due to uncertainties over the evolution and the competitiveness of the Greek electricity market, given the absolute dominant position of the incumbent PPC.

An important obstacle to new entry has been access to fuel. A potential entrant has to negotiate the price for Natural Gas[15] with the state-owned monopolist DEPA which

[15] Only NG-fuelled plants are licensed for environmental reasons.

in turn has a "most favoured customer" arrangement with PPC. According to the recent amendment of the Electricity Law, from 01.07.2005 the Natural Gas TSO will be obliged to provide to electricity producers access to the transmission system on the basis of published transmission tariffs approved by the Ministry of Development after recommendation from RAE.

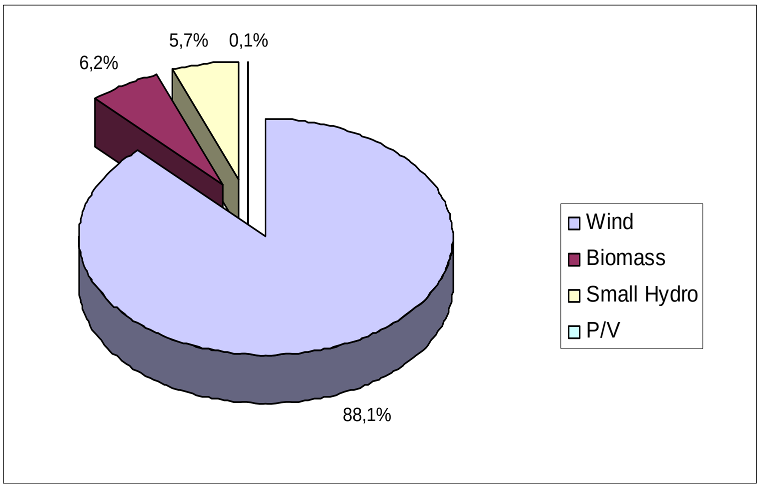
Another obstacle is that PPC doesn't issue separate accounts for its mining, generation, distribution and supply activities. Potential new entrants fear that PPC could cross-subsidize its generation segment and offer lower tariffs to the eligible large consumers, undermining the new entrants ability to form a customer base.

3.2.5. Renewable energy sources.

Electricity production from renewable energy sources (RES) in Greece was 6.39 TWh[16] in 2003 (11.85% of total production) up from 1.77 TWh in 1990 (5.1% of total production).

In terms of installed capacity (excluding large hydro plants) the vast majority of RES plants in Greece are wind-powered (see Figure 10). As shown in Figure 11, the wind energy sector has made a significant progress during the last five years and wind turbine installed capacity is expected to be around 550MW by the end of 2004

Figure 10: RES capacity per type installed in Greece by end of 2003



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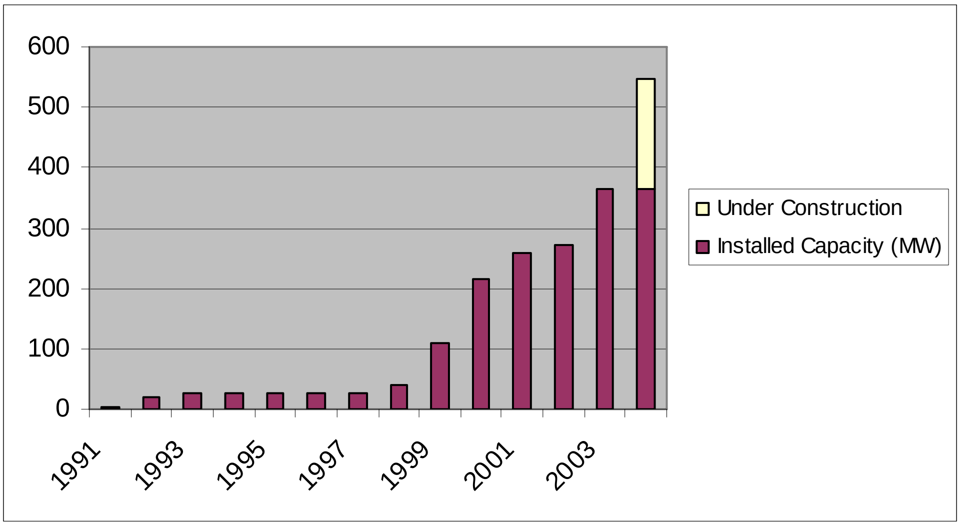
[16] Including large hydro plants

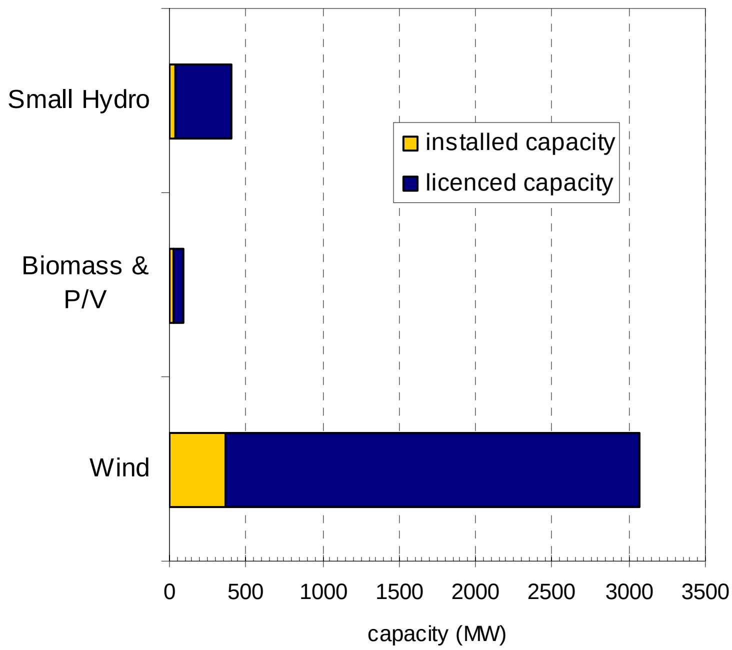
Figure 11: Development of wind turbine installed capacity in Greece



Greece has taken steps to promote electricity production from RES mainly by guaranteeing priority of access to the transmission grid and through a feed-in tariff system. Moreover, under EU's Community Support Framework, investment in RES projects is subsidized by up to 40% of investment cost.

With the opening up of the Greek electricity market in 2001, there was an outstanding investor interest for RES installations. From February 2001 to June 2004, the Ministry of Development has issued Generation Licenses for RES installations totaling 4.2GW.

Figure 12: Installed and licensed capacity of RES installations by end of 2003



However implementation of RES projects has been slow the past 3 years mainly due to complicated and bureaucratic licensing procedures as well as local oppositions.

EU's Directive 2001/77/EC has set a

20.1% target of RES electricity contribution by 2010 for Greece, including large hydro plants. This ambitious target is unlikely to be reached unless the financial incentives continue to be provided, the bureaucratic barriers are overcome and public acceptance is increased.

3.3. Distinctive characteristics of the Greek Electricity Sector with regard to the ETS

This section discusses the most distinctive characteristics of the Greek Electricity Sector with regard to the production of the National Allocation Plan and the implementation of the EATS.

3.3.1. Dominance of PPC

The incumbent utility Public Power Corporation (PPC) (became a Societe Anonyme in 2001) has a de facto monopoly on the electricity sector. It is vertically integrated in all aspects of the electricity sector: lignite supply, generation, distribution and supply and owns the Transmission grid operated by the HTSO. There exist no obligations about managerial or legal unbundling of the Distribution System Operator from PPC.

Its market share in generation capacity was 97% in 2002, the majority of the rest being autoproducers. In the Supply sub-sector of the electricity market, its market share is 100% (see next paragraph).

Due to its de facto monopoly, PPC could take advantage of the “pooling” provision under Article 28 of the Directive and manage from head-office any exchange of allowances between its installations in order to comply with the EU ETS. Of course, such a pool would be subject to formal provision in national law and acceptance from the Commission. However, due to the delays in drawing up the Greek NAP, no information on an intention on behalf of PPC to apply for such a pool is yet available.

In the future allowances market in the electricity sector, PPC could act as a monopsony, raising fears that it could exercise market power either by raising the price of allowances or by withholding allowances from the market.

3.3.2. Supply sub-sector liberalisation

According to the Greek Electricity Law, consumers connected to “Medium” and High Voltage (above 1 kV), representing 34% of the market, are free to choose their electricity supplier. From July 2004 all customers except households will be eligible customers. Full market opening is envisioned for July 2007. Supply to captive customers is reserved to PPC which is also the supplier of last resort for eligible customers. Tariffs for each category of customer are approved by the Ministry of Development after recommendation from RAE based on evidence of annual growth of cost elements. Approval of tariffs for eligible customers by the Ministry of development will be necessary while PPC has a market share of over 70% in the supply sub-sector. In any case, eligibility of customers is not applicable in the non-interconnected islands where PPC is the exclusive supplier and single buyer.

Although RAE and the Ministry of Development have issued licenses to 10 other Electricity Suppliers of 2,343MW, no one has yet assumed activities in Greece and PPC supplied 100% of electricity as of end 2003 with the exception of 20MW which are directly imported by Aluminium of Greece SA for its own use.

Increased production costs resulting from the implementation of the EU ETS are likely to be reflected on the electricity tariffs, and this is an issue that the relevant authorities will soon have to deal with.

3.3.3. Dominance of lignite & security of supply

Lignite is the major domestic energy source in Greece. While the Greek State owns the deposits, PPC exploits them under license from the state. Private mines extract and sell to the PPC less than 5% of total lignite mined.

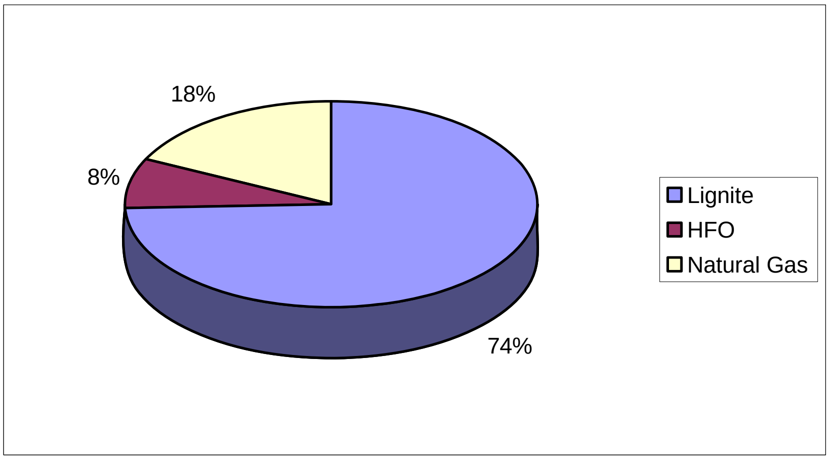
Total capacity of lignite-fired power plants in the mainland grid was 5.288 MW in 2003 or 47% of the total of 11.224 MW.

Electricity production from lignite was 32.133 GWh in 2003 or 74% of net thermal electricity production.

Figures 10 and 11 illustrate the dominant role of lignite in electricity generation in Greece.

If Greece is to meet its emissions reductions targets, it is deemed necessary that lignite share in electricity production is reduced. In this context, the Greek Government issues Generation Licenses only to natural gas-fired plants.

Figure 13: Electricity production from thermal plants by fuel type



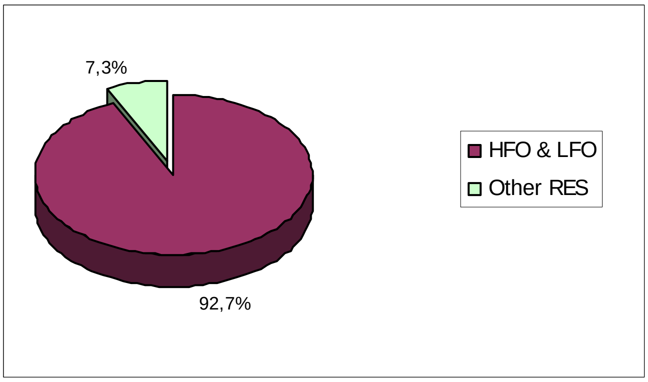
However, a massive trend away from lignite could raise issues of national energy security since lignite is the only significant domestic energy source in Greece (besides Renewable energy).

3.3.4. Non-interconnected islands

Greece has a large number of islands with autonomous systems not interconnected with the mainland Grid, with total installed capacity of 1472.4 MW. As illustrated in

Figure 14 92.7% of installed capacity in the non-interconnected islands is oil-fired. In terms of electricity generation, oil accounts for 98.3% of production.

Figure 14: Installed capacity in the non-interconnected islands by energy source



Installations in 12 non-interconnected islands are expected to be covered by the scheme, with the rest being serviced from smaller installations. These islands are: Crete, Rhodes, Kos, Santorini, Myconos, Kalymnos, Lesvos, Limnos, Paros, Samos, Syros and Chios.

Almost all islands have a high potential for renewable energy but system stability issues limit the RES contribution to 15%. The small size of the autonomous systems, with the likely exception of Crete, makes penetration of natural gas economically infeasible. Moreover, as demand is driven mainly by the tourism industry, peak load during summer months can exceed the winter peak load many times over and electricity demand is very inelastic and exhibits a high annual rate of increase. Electricity consumption in all the non-interconnected islands increased by 6.1% from 2001 to 2002 compared to 3.0% for mainland Greece.

Therefore, the potential for emissions reductions in the islands' electricity generation is very limited and this will be reflected in the NAP.

3.3.5. Interconnectors

The Greek Transmission System is interconnected with Italy with a 500 MW DC link[17] and with its northern neighbours (Albania, FYROM, and Bulgaria) with interconnectors with total available capacity of 600 MW. Another interconnection with Bulgaria is being planned as well as one linking the Greek to the Turkish System but they are not expected to be completed before the end of the decade. The total interconnector capacity of the Greek System therefore amounts to about 10% of installed generation capacity indicating that the Greek electricity market faces limited international competition.

In 2003 net imports of electricity were 2,100 GWh or 3.7% of total electricity consumption while exports (including transits) reached 1,124 GWh. The breakdown of imports/exports by origin/destination as shown in Table 8 clearly indicates a pattern of imports from the northern interconnectors, mainly from Bulgaria where the electricity price is lower than in Greece due to generation overcapacity and the utilisation of nuclear plants The bulk of electricity exports are towards Italy, where the price of electricity is higher and generation capacity is limited. Exports via the Italian interconnector take place mainly from October to June, that is during the period where the Greek system does not experience its peak load.

Table 8: Electricity imports & exports in 2003. Source HTSO

	Electricity flows in 2003 (MWh)	
	Italy	**Northern**
Imports	26,400	3,308,210
Exports	1,124,014	63,945

[17] Only 300 MW are available for exports due to technical restrictions in the Italian System.

Emissions trading is likely to lead to an increased utilisation of the northern interconnections since the three neighbouring countries are not affected by the scheme and their electricity generation industry will have a competitive advantage relative to the Greek. In particular, in the case that domestic production cost plus the allowance price is greater than the import price plus transmission costs, it would be more profitable for the Greek system to import electricity rather than produce it, subject to interconnectors' available capacity. In this context, there is a potential incentive for Greek generators to build new thermal plants in one of those countries where GHG emissions are not regulated.

4. Concluding remarks

This report describes RAE's contribution towards the fulfillment of Tasks 1 and 2 of the ETRES project with emphasis on the implementation of the EU emission allowance trading scheme in the Greek Electricity Sector.

The Emissions Allowances Trading Scheme will be in place shortly adding a carbon constraint to the European economy with significant implications in the EU industrial sectors. Existing studies reveal that emissions trading will result to higher wholesale prices (due to the increased production costs) but also fuel switching from coal to the more carbon-efficient natural gas. However, since natural gas is mainly imported in the EU, a significant increase in its consumption could increase EU's energy import dependence to levels that might be a source of concern.

The Greek electricity sector will have a major role in the EU ETS at the national level, given its share in CO_2 emissions. In order for the scheme to be implemented in Greece successfully and with a cost-effective manner, the Greek Authorities should:

- Evaluate the cost-effectiveness of policies and measures required to achieve the Kyoto target, especially for the sectors not covered by the EU ETS such as the transport sector.
- Develop a long-term strategy for optimal fuel mix in electricity generation striking a balance between national energy security and GHG emissions mitigation, given the rapidly growing share of natural gas.
- Provide market certainty by clarifying its vision for the overall market design and structure. This would facilitate market competition and expedite the construction of new generating capacity, ensuring at the same time mid-term security of supply.
- Continue the liberalisation process of the electricity market and prevent abuse of the incumbent's dominant market position.
- Continue efforts to develop an Electricity Market in Southeastern Europe by increasing usable capacity of interconnectors.

- Facilitate the increased penetration of renewables by streamlining the authorisation procedures for setting up such projects and informing the general public.

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