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PRICES AND TARIFF POLICY IN ENERGY SUPPLY

"PRICING OF ENERGY IN TIMES OF CHANGE - SOME KEY ISSUES"

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1. Introduction

For the conservative eye, times of paradigm changes are always filled with paradoxes:

* Currently, in a large number of countries around the world, new regulatory systems for the so-called natural monopolies in gas, power and district heating are implemented or are under consideration which intend to establish new pricing rules which better reflect the competitive market for the supply of gas and electricity. The paradox is that as *technical efficiency* is being replaced by *allocative* or *price efficiency* as the motivating force for regulation, price efficiency may suffer at least in the short term.

* A few years after price controls for the individual fuels oil products and coal have been almost universally abolished, the CO_2 and SO_2 taxation debate once more brings the pricing issue for these fuels back into the energy administrations.

The world of energy planning and pricing has become a very difficult place:

* In the short to medium term, the introduction of rational pricing by utilities in countries in transition will continue to be blocked by serious willingness to pay problems

* Increased international competition limits the potential for finding independent national solutions to energy pricing. In particular "green taxation" is confronted with serious implementation difficulties

* Deregulation reduces the potential for direct application of the LRMC rule for economic pricing and calls instead for the design of efficient markets for bulk supply. Economic prices cannot be imposed on deregulated electricity and natural gas markets, and oligopolistic market structures threaten to block for the achievement of economic pricing through the forces of competition.

Energy planners can no longer apply clear cut "cooking books" rules to energy pricing that are supported by theory and applicable to practice, but have to find "second best solutions" in what is often a trial and error approach. There is not much help to be found in theories on second best pricing for markets that are characterized by severe price distortions in general. Instead the utilities have to improvise practical survival solutions. The situation in the present energy markets seems to confirm the punctuated equilibrium theory which posits that evolutionary change occurs in sudden outbursts, driven in part by external environmental forces. In the meantime, *energy pricing becomes a "social engineering task"* involving coordination of efforts across ministerial boundaries in an integrated approach comprising pricing as well as the design of regulatory frameworks and of market place arrangements.

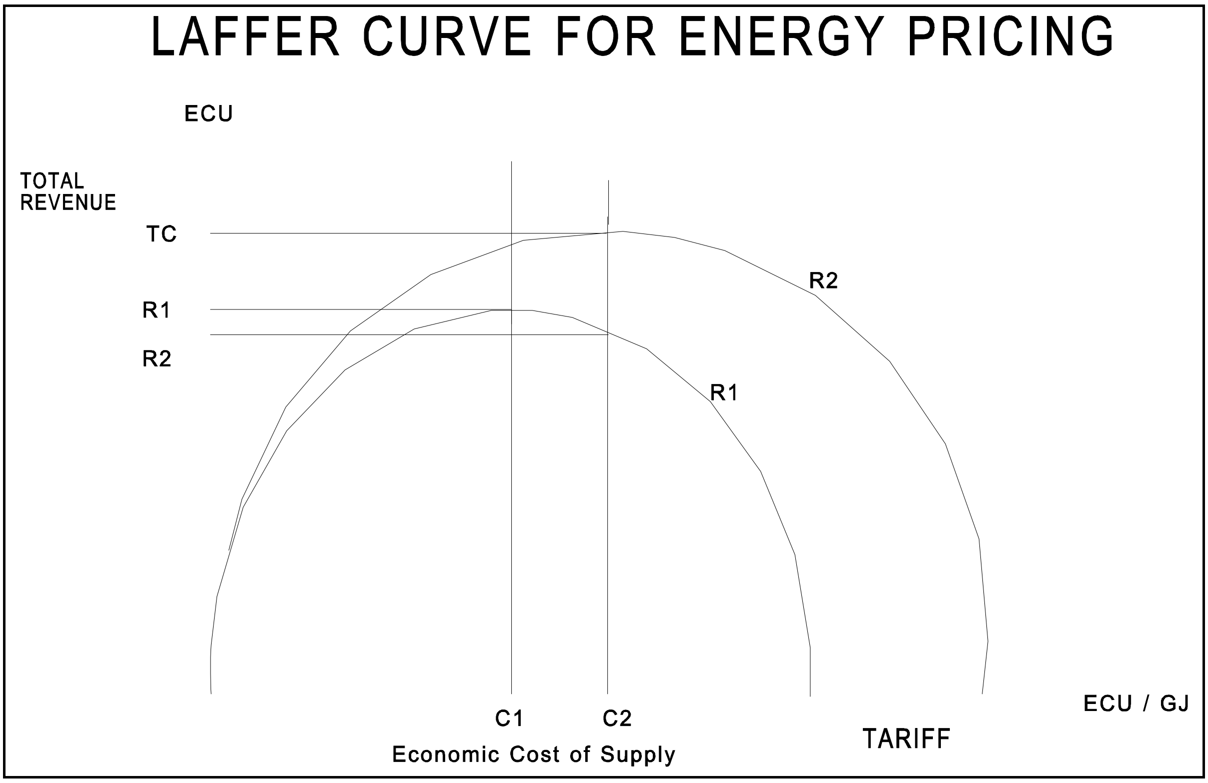
2. The Ability to Pay Problem

It is well known that the utilities in the European countries in transition have been confronted by severe ability to pay problems of household as well as of industrial consumers. The ability to pay problem is caused by the fact that the changes in relative prices brought about by the introduction of a market economy have been particularly pronounced in the energy sector. In EU countries, the total cost of telecommunications, water and domestic energy amounts to no more than 8% of average household expenditure. The table shows the situation in the USA as an example. In the transitional economies, the corresponding figure is much higher.

Table 1: Household Expenditure on Utility Services, USA 1991

	In percent of Total Household Expenditure
Electricity:	1.9%
Communications:	1.4%
Transportation	1.0%
Gas	0.7%
Water	0.7%
TOTAL	5.7%

The achievement of full cost pricing in these countries has been prevented by the fact that the willingness-to-pay of consumers is below the level needed to cover the full economic cost of supply. This gives rise to the *"Laffer curve of Eastern European energy pricing"* which is shown in figure 1 below.



The present situation in most Eastern European countries is shown by the “total revenue curve” / “energy Laffer curve” (an expression of the “consumer willingness to pay curve”) **R1** and the average cost per GJ of **C2**. The existing tariff of **C1** is lower than the cost C2 and the enterprises are producing at a loss equal to an annual shortage of revenue equal to **TC-R1**. From the point of view of the energy company (and of the ministry of energy) the pricing policy is rational as it maximizes total revenues for the company. If the higher full cost price of C2 was charged, total revenues would go down to **R2** as an increasing number of consumers would refuse to pay at all. The situation is particularly severe in the district heating sector because heating costs make up a much larger percentage of household expenditures than electricity and because as yet few consumers have the possibility to regulate consumption by using thermostats. In the oil and coal industry, pricing does not pose a problem since supplies are discontinuous and non-paying consumers are “interrupted” automatically.

In order to get out of their loss-making situation, the energy utilities can attempt (i) to shift the “average cost curve” inwards from C2 to C1 or (ii) to push the "Laffer-curve for energy company revenue” outwards from R1 to R2; or (iii) to do both. In the short run both options are difficult to apply successfully:

* Although productivity in the Eastern Europeans energy companies is much lower than in the EU (implying a large scope for efficiency gains) it is hard for the companies to reduce their *average cost of supply* significantly below existing levels:
    - With wage and salary levels of staff still being underpriced (due to continued price distortions inter alia in the housing sector), a reduction in the number of staff has little influence on the total cost of production.
    - Existing capital stock is largely “written off” in the accountancy books and does not enter the price structure at full replacement value.
    - Improvements in energy efficiency demand prior “high cost” investments which enter into costs immediately [1], whereas the benefits in terms of operational savings turn up over the coming years.

* The *position of the “energy Laffer curve”* depends on the consumers’ “*ability to pay*” within the constraints of their household budgets as well as their “*willingness to pay*”. Both are highly influenced by policy initiatives outside the energy sector:

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[1] For companies, such as the Czech power companies which have no difficulties in raising capital internationally, this is not a major constraint. The cost of investment is amortized over the economic lifetime of the equipment and can be matched by savings. For capital starved firms there are important opportunity costs in terms of foregone alternative investments opportunities.

- Energy companies can improve the *"ability to pay"* by providing DSM services to consumers. But more important is the economic growth of the economy and the adoption of specific legislation in social sector - rising minimum salary, unemployment benefits, laws permitting social compensation payments to low income households.
- *"Willingness to pay"* can be influenced directly by the energy companies through the provision of better service and in the district heating sector through assistance in the installment of thermostats in apartment buildings. But service improvements are difficult to achieve as long as incoming revenue falls short of full cost coverage. In addition willingness to pay is improved by the imposition of sanctions in cases of non-payment (easier in electricity than in district heating). But particularly in district heating, use of sanctions require prior changes in laws and in the organization of housing associations.

The point of the “energy Laffer curve” discussion is that an analysis of the present status of the transformation process in the energy sector has to look beyond the energy sector as such and must look at a number of regulatory and legal reforms in other areas, in particular in social policy. Some countries, e.g. Latvia, have adopted social legislation permitting municipalities to provide income support to low income citizens in order to enable them to pay their energy bills (and have provided state funding for this purpose). Other countries have not yet such legislation in place. In Poland, for example, subsidies can be paid only to cooperatives and to companies, not to individual households (situation until 1995).

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3. The Meaning of Full Cost Coverage

The meaning of full cost pricing of energy in an environment characterized by radically changing relative prices and the continued existence of severe price distortions is an issue which is debated by energy economists in Eastern Europe. O&M costs can be identified easily. The difficult issue as always is the definition of the cost of capital. In several Eastern European utilities a large part assets is fully depreciated and the book value of the remaining assets has been eroded by inflation. Under these conditions, the book value of annual depreciation is very low. Although the utilities may get full cost coverage by using the historical cost figures in their pricing methodology, it is obvious that the resulting prices are substantially below the LRMC of supply. Adjustments are being made to base asset value on the cost of replacement, but a frequently encountered practical problem is how to value outmoded technology.

The definition of full cost pricing has to satisfy two considerations: (i) it has to be forward looking and not backward looking; (ii) it has to be related to the cost of capital and take into account that energy utilities in a market economy are operated on the basis of commercial criteria. Even if a utility is organised as a municipal department it should let its rate of return requirements be guided by the rates of return on capital that are achieved by commercialized companies. *Commercialization* should be defined as meaning (i) that the concerned companies are organised in the form of share holding companies (either limited liability or joint stock company), (ii) have a normal capital structure (appropriate ratio between equity and debt financing) and (iii) are operated on the basis of strictly commercial criteria.

Based on the above considerations, the tariff which allows full cost coverage in the Eastern European Power and heat sector can be defined as ***the minimum tariff required to sustain the long run commercial viability of the companies***. This, of course, begs the question of the definition of commercial viability:

* *Commercial viability in the short run* means to be price competitive on the market and yet have full coverage of operating costs including payments of interests.
* In the *longer run, commercial viability* depends on the continued ability to attract capital for the financing of needed investments. *The rule of thumb for long term commercial viability* (under the present tight financial and socio-economic conditions in Eastern Europe) *is that* ***the level of tariff should allow at least 30% self-financing of investments and generate a rate of return of at least 5 percent on assets***.

The appropriate *level of self-financing* is defined from an analysis of what the optimal capital structure is for an utility, and what level of self-financing is needed to achieve it. The issue of *optimal capital structure* concerns the ratio between equity and debt capital on the balance sheet. The balance sheet of a company lists assets at cost and shows how these assets are financed in the form of liabilities (long and short term debt to creditors) and equity (owners own investments). Normally, *equity* is a more expensive form of finance than *interest bearing capital* (debt) because the risk associated with equity is higher: unlike interest payments, the dividend is not fixed and if the company goes bankrupt, the equity owners are the last to get their claims taken into account. Therefore, a company will seek to get as much debt capital as possible [2]. At a certain level of indebtness, however, creditors become concerned about the "under-capitalisation" of the company and will refuse to provide new loans or insist on a higher rate of interest to compensate for the increased risk of the loan. At this point in time, the issue of new equity becomes a cheaper form of finance than debt capital. The optimal ratio (capital structure) is the ratio which minimizes the overall cost of capital. The ratio depends on the riskiness of the industry (the more risky, the more equity is needed) and the characteristics of the national capital market (the more developed and liquid, the higher the equity share can be). But international experience indicates that a 40%/60% split between equity and debt financing is an approproppriate capital structure for a commercialised power company.

The "total revenue requirement method" of rate setting: $TR = OC + (I-D) * r$ states that a utility in order to be commercially viable needs to have a total revenue, TR, which covers the total cost of operation, OC, and provides an adequate rate or return, r, on its depreciated assets, I = accumulated investment minus D = accumulated depreciation. The appropriate *rate of return, r,* is defined by the level which is needed to attract finance in the longer turn, subject to the constraint posed by the ability to pay problem confronted by Eastern European utilities. In order to determine what level is appropriate, regulators take a look at what rates of return are achieved in other industries of comparable risk. The riskier an industry, the higher is the rate required by equity investors.

[2] In the build-up phase of a company or of a new business area, though, it is an advantage for the company that dividend payments can be postponed until sufficient profit and cash are available. In that case, equity is cheaper as well.

4. The Free Market and LRMC Pricing[3]

The main concerns of regulation are to ensure (i) the efficiency of generation investment choices, and (ii) sound pricing principles. Both are long-term issues: investment choices account for two-thirds of the consumer kWh cost, and proper pricing principles help properly orient the decentralized choices of consumers.

During the last twenty years there has been general consensus among power economists that the ideal pricing principle for utilities is to base prices on the long run marginal cost of supply (LRMC). The beauty of LRMC pricing is that it simultaneously sends the correct efficiency signals to the demand as well as to the supply side: consumers make the decisions concerning their levels of consumption (and of energy saving) on the true cost of their marginal consumption to the utilities; and utilities base their decisions concerning the expansion of capacity on a proper comparison of the cost of marginal capacity additions and the value of the marginal supply to consumers.

Despite the general agreement on the merits of the LRMC pricing principle, relatively few utilities under traditional "natural monopoly" rate of return regulation made proper use of it. The most notable exception was EdF, the pioneer of LRMC pricing. Otherwise, historical cost recovery or market pricing methods tended to dominate and in many other countries, local concerns for industrial competitiveness or for household consumers (voters) led to cross subsidisation of either industrial or of household consumption. Yet, in theory, LRMC pricing could be imposed on the utilities and be practised by them in the traditional world of "natural monopoly" organisation of power supply.

In free markets involving TPA and spot markets, that principle can no longer be imposed nor can it be easily applied. Once we turn to market based pricing we have to accept that prices can vascillate around the long-term optimum. In times of scarcity, tariffs will be above LRMC; in times of surplus capacity below LRMC. In the short run, the vascillations can be substantial: the Norwegian spot market during its first year of operation experienced price ranges from NK 0.015 to 0.55, that is, a factor of almost 40 between the highest and the lowest price! The best which can be hoped for in a deregulated power market is that in the long run, on average, prices will be around LRMC.

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[3] In the countries in transition, LRMC pricing may not be the appropriate pricing policy for utilities. In an economy with distortions elsewhere, second best analysis establishes that efficiency seeking monopoly should not necessarily require marginal cost pricing.

In theoretical litterature the search of innovative techniques for incentive regulation in deregulated markets has not produced any useful and widely accepted substitute for the rule to "base prices on marginal costs". LRMC pricing continues to be the guiding rule for regulators to judge the efficiency of the power and natural gas markets. But the regulator's task of identifying tariffs that correctly reflect the LRMC of supply and to impose its application on the utilities, is replaced by the wider social engineering task of defining and implementing the type of market organisation that is most conducive to approximate LRMC pricing in practice. The search for such institutional arrangements to the satisfaction of all stake holders is devilishly complex. The objective of reaching commercial solutions has to be reconciled with wider public policy issues such as equity and environmental considerations [4]. Each country has to find arrangements that fit to its national environment. As existing regulatory litterature provides no more than a few and very general orientations, the task turns into a trial and error exercise.

The promotion of genuine competition in generation being the key objective of regulatory reform, the design of the wholesale market place for power becomes the key issue for energy planners. Once a power utility is no longer vertically integrated there is a need to develop and to provide appropriate signals to the *wholesale market* as opposed to *end users*. This involves:

- to signal short run marginal costs through multi-part pricing structures
- to ensure average costs are comparable to the competitive new generation level
- to ensure transmission pricing transparency and open access to the market for generation competitors.

In *England,* the challenge was to define a power pool which could produce competitive pricing in an industry that had a typical oligopolistic industry structure. It turned out, as many energy economists had expected, that the institutional market arrangements did not function sufficiently well - there were clear signs of oligopolistic pricing behaviour. After a year of operation of the pool, the power regulator OFFER had to impose price caps on the power pool, a solution which is contrary to the idea of a deregulated and free market for power generation. In late 1995 the price cap was lifted but the generators know that the price cap will be reimposed if pool prices do not develop to the satisfaction of the regulator.

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[4] An illustrative example is the conclusion of purchase power agreements (PPAs) with with independent power producers (IPPs) who use renewable energy systems. In monopoly regulated systems IPPs can be paid on the basis of avoided cost of the regulated power company. In a free market system, a special investive bonus per kWh can be passed to such producers through a levy on the transmission system, whereas the rest of the price has to be established by market forces.

In *Norway*, the industry structure is very competitive consisting of more than 70 independent hydropower companies with an overall surplus of capacity. The price fluctuations in the pool[5] are caused by the nature of the generating technology: hydropower has low operating costs and when there is lots of rainfall (and melting snow) the reservoirs become full and overspill; whereas lack of rainfall causes low reservoirs and scarcity. Together this provides for the possibility that prices can fall down to the level of operating costs or rise almost to the level of the marginal cost to the consumer of power shortages. The challenge is to define organisational mechanisms that can cope with the price forming weaknesses of a purely hydropower based system. It turned out that Norway had one "god given" institutional arrangement for achieving a downward price cap in the form of a market leader: Statkraft, the largest generator with 30% of production capacity announced it would no longer sell power to the pool at any price below NK 0.10. The others followed. A more permanent solution was to improve the market for exports of power. In the case of a well functioning and transparent export market, the floor price of the power pool would be set not by Statkraft's position, but by the short run marginal cost of alternative thermal production in the importing countries. The solution to reduce the potential for an upward movement of the pool price was to improve the potential for imports. In short, the solution to excessive price fluctuations was to improve foreign trading in general. Beginning January 1, 1996, Norway, Sweden and Finland will operate a common Nordic market for electricity and Denmark may join in a few years time. The pool price will become more stable not so much as a result of more actors entering the market but because of the arrival of different types of generators: Sweden has an important nuclear power industry, the power industry in Finland and in Denmark is dominated by thermal power.

Electricity trading in Norway is based upon "point tariffs". i.e. tariffs for transport that depend on where power is fed into the system and where it is taken out, but not on the distance between the two places. That is, a buyer pays the same price for transport and distribution independent of where in the grid the seller is placed. The introduction of point tariffs was considered absolutely necessary in order to have a functioning market. But, obviously, point tariffs do not provide appropriate locational price signals to investors who want to set up a new power plant. Wheras this causes very minor distortions in a small country, the long geography of Norway leads to not insignificant line losses in power transport.

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[5] Electricity can be traded in four different ways in Norway. There are bilateral agreements negotiated between individual buyers and sellers. In addition there is the pool market with three different arrangements: the futures market (which offers standard contracts on a weekly basis for maximum five years ahead), the ordinary spot market (where prices are fixed daily for the next 24 hours) and the instant market (which is used to adjust for imperfect demand forecasts and is open to producers that can adjust production at 15 minutes notice).

5. Limits to Internalization of Externalities

Economists have argued for years that external costs and benefits of energy supply have to be “internalised” in power tariffs and in other energy prices in order to provide consumers and investors with the correct pricing signals. Economic theory on the internalisation of external effects in product pricing recommends to impose a tax (or in the case of positive externalities, a subsidy) equal to the value of the external effect. By doing this, the price paid by a consumer for a marginal expansion of energy consumption (or his financial benefit in case of a reduction in consumption) will equal its total cost (value) to society.

In recent years “green energy taxation” has gained increasing political support driven by two developments:

* Sustainability now is not an issue of oil in the ground but of pollutants in the air. The pledge by OECD countries at the Rio Conference in 1992 to stabilise their CO_2 emissions in 2005 at the 1990 level of emissions has accelerated the active search to identify least cost ways of achieving a reduction in energy consumption. It is widely recognized (and proven by the 1973 and 1979 demand reactions to oil price increases) that correct energy pricing is the most potent of all energy policy instruments which energy policy makers have available to achieve a given demand target. *Green taxation is seen as an efficient market based instrument to achieve pollution abatement targets*.

* The continued stabilization of unemployment in OECD countries at very high levels has led to a focus on structural factors rather than demand factors as explanatory variables for unemployment and to the formulation of proposals for structural reforms. One structural factor which has been pointed out is the impact of over-taxation of labor (e.g. through social security contributions) and under-taxation of other factor inputs on the relative cost of labor compared to the cost of other production factors. It is illogical to overtax(price) the production factor labor, the consumption of which politicians want to promote, and to undertax fuels, the consumption of which politicians want to reduce for environmental reasons, by not including the external cost of their pollution into their price structures. *The ability of green taxation to shift the relative factor prices in favor of labor is promoted as an instrument of employment generation.*

In several countries, legislation for CO_2 and SO_2 taxation has been introduced or is being debated. In the design and the implementation of environmental energy taxation, policy makers have to be aware of two major trade-offs:

* Between energy-environmental gains from “fine-tuning” of tax rates and the practical “cost of application” of such fine tuning in terms of, above all, administrative costs;
* Between energy-environmental objectives and industrial-employment objectives.

The last trade-off may seem surprising in view of the employment generating objective of green taxation. It is due to the very different macroeconomic effects of raising industrial energy prices which are an economic input and of raising household end-use prices in an open economy. Just as the impact of CO_2 and SO_2 emissions has transnational effects, so does the impact of CO_2 and SO_2 taxation when it is implemented without coordination with the major trading partners.

This is illustrated by the experience of the Danish government's introduction of CO_2 and SO_2 taxation beginning January 1996. Since the beginning of the 1990s, the EU-Commission has attempted to get the EU-council to adopt a directive on the joint introduction by member states of CO_2 and SO_2 taxation. But without success so far. Whereas the Northern countries Denmark, Germany and Holland supported the proposal, the Southern countries Greece and Spain opposed it. Frustrated by the lack of EU progress in this area, the Dutch and the Danish Government decided to go ahead on their own. By doing so, both countries face the difficult task of implementing CO_2 taxation without jeopardizing the international competitiveness of their industries. The Danish energy planners were confronted with the following situation:

* Energy consumption of households was very heavily taxed [6], whereas energy consumption in industry was almost totally tax exempted.

* The cost of energy on average amounts to no more than 1.6% of the total cost of production in Danish manufacturing industry [7]. Although compared to the level of profits, the share becomes much more important, the impact on costs is too low to motivate managers to pay particular attention to energy savings. Therefore, a CO_2 tax has to be high in order to achieve a measurable impact in the average industry.

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[6] When international oil prices fell in 1986, the Danish government decided to "protect consumers against the impact of falling energy prices". A flexible taxation was introduced on oil products that maintained final consumer prices at pre-1986 levels at least in nominal price levels. When the oil price falls, taxes are increased; when they rise, decreased.

[7] This average is very low by international standards - the figure in Germany, for example, is 4.6%. The low cost of production is not due to a high efficiency of energy use - although Danish industry scores well in branch to branch comparisons - but due to the structure of manufacturing industry: Denmark has a low share of heavy industry.

* In the energy intensive industries, cement, glass, steel, pulp and paper, brick production, ceramics, the consumption of energy is an important cost factor amounting to more than 15% of the total cost of production. These industries face very tough international competition. Their products are standard mass production goods where price is the only competitive determinant. A high CO_2 tax would undermine the international competitiveness of these industries and price them out of the market. This would hurt domestic unemployment as well as the achievement of CO_2 abatement: imported products would have similar CO_2 emissions in their production and the transport to Denmark would cause added CO_2 emissions. In addition, because energy already is an important cost element, a high CO_2 tax is not needed to motivate managers to pay attention to energy savings. Normally, energy intensive industries are already very energy efficient. Energy audits in these industries show limited economic potential for further improvements [8].

* The consumption of the 14 largest industrial energy users amounted to 1/3 of total industrial energy consumption.

* The Government instructed that the introduction of the CO_2 taxation should cause minimum negative impact on the international competitiveness of Danish industry.

The cost of marginal CO_2 emissions can be estimated by two different methods. Either by estimating the cost imposed on society by the external impact of the additional CO_2 emissions in terms of health effects, production effects, etc; or by estimating the cost of abatement measures that are needed to keep society's total level of CO_2 emission constant. The lowest of the two estimates provides the cost to society. The first method can be ruled out in practice: no method is available that can provide a justified quantification of the external economic costs of increased global warming which is believed to result from an increase in CO_2 levels. Estimates exist of the cost of abatement investments that are needed to achieve the adopted CO_2 emission targets in OECD countries. These *cost estimates range from US$10 to 50 per ton of reduced CO_2 emission*. The level is highly sensitive to the choice of year for the achievement of a given CO_2 emission target. To advance the date by as little as five years can easily double or triple the cost of investment.

In order to be economically efficient, CO_2 taxation has to be equal to the cost imposed by additional CO_2 emissions. In order to serve as an efficient allocative mechamism, this rate must be imposed uniformly across sectors and fuels. Whether an increase in CO_2 is caused by an

[8] Although industrial energy prices have returned almost to 1972 levels in real terms, the oil price chocks in 1973 and 1979 promoted the achievement of a high energy efficiency in these industries. They accelerated the development of more energy efficient processes. International data show that the percentage reduction in energy use achieved by the energy intensive industries was higher than the average for manufacturing industry.

increase in the energy consumption of households or of industry is irrelevant, the cost to society is the same. However, economic efficiency considerations have never been a determinant factor for Danish energy taxation. The level of energy taxes was determined by a mixture of fiscal motives and energy policy motives, in particular, the wish to protect the ambitious program for the expansion of CHP production and its associated investments in district heating transport systems. The promotion of least cost measures plays hardly any role. The high tax on residential heating oil amounts to an implicit CO_2 tax of DKK 600 (US$110) per ton CO_2 and subsidies are given to households for the purchase of solar heating systems that can reduce CO_2 emissions at an investment cost of DKK 1200 (US$220) per ton saved CO_2 emission.

The introduction of a uniform rate of CO_2 taxation, however, was effectively blocked by the decision of the Danish Government to go alone within the framework of the internal market in the EU and the need to protect the survival of the energy intensive industries. The resulting need for adjustments and compromises between energy and industrial policy objectives turned the final scheme into a nightmare of bureaucracy. Its main features are summarized below.

The law introduced a SO_2 tax of DKK 0.1/kg SO_2 (US$ 0.02). The impact of the introduction of a new CO_2 tax on the international competitiveness of Danish industry was reduced by five sets of measures:

* A phased approach is used whereby the CO_2 taxation rates will be increased gradually over the next four years.

* During the first four years, the scheme is designed to result in zero revenue generation for the state budget. The revenue that is generated by the CO_2 tax is "channeled back into industry" by (i) a reduction in the level of the labor market contributions that employers have to pay, and (ii) by the creation of a 30% subsidy scheme for energy saving investments. The reduction in labor market contributions is, in principle, permanent; and perfectly in line with the CO_2 taxation idea of shifting the relative factor costs of production in favor of labor. The subsidy scheme is supposed to last four years only in order to motivate industry to take action now rather than later.

* Industries that sign an energy reduction contract with the Danish Energy Agency committing them to implement energy saving measures identified by an audit carried out by a certified consultant pay a lower CO_2 taxation rate.

* The lowest CO_2 taxation rates are paid by the energy intensive industry. A distinction is made between "energy intensive industrial processes" (a list of 31 industrial processes) and "non-energy intensive industrial processes". Depending on whether or not an energy reduction contract has been signed, the former will pay DKK 3-25/ton CO_2 (US$ 0.55-4.5), the other DKK 68-90/ton CO_2 (US$ 11-16).

* No CO_2 or SO_2 taxes are paid for fuel use in power generation as this would have reduced power exports and increased power imports without any global CO_2 savings. Instead, the final consumer price includes a CO_2 levy of 0.1 DKK/kWh (US$ 0.02) and a SO_2 levy of 0.009 DKK/kWh which increases to 0.013 DKK/kWh in 1999.

Until the very end of the adoption of the law by the Parliament it was uncertain whether the scheme containing specially low taxation rates for energy intensive industries would be approved by the EU Commission or whether this aspect would be declared an illegal subsidy to an industry. After long negotiations, however, the Commission approved the draft law. It is certain that it would not have been approved by Parliament otherwise.

Further complications were added to the scheme by "fine tuning" ambitions that resulted in the addition of a third category of industrial energy use: *heating of industrial premises*. It was decided that energy use for heating should be taxed at the same rate in industry as for residential consumers, that is, at *DKK 600/ton CO_2.* This distinction will result in very modest environmental benefits: energy for heating amounts to no more than 7% of industrial energy use. But it will add substantially to the bureaucratic cost of administering the programme in the enterprises who have to audit and register the part of their energy consumption which is used for "industrial processes" and for "heating" respectively. The distinction is not logical in all industries. Car painters, for example, need to have a temperature of 23 degrees Celsius in their workshop in order for the lacks to dry. Since the temperature for room/comfort heating is usually no more than 20 degrees, is this energy consumption "process" or "heating"? Also, industrial firms that use "waste heat" from their "process heat" for the heating of their premises, are taxed on the "implicit/calculated" CO_2 content of this waste heat.

The scheme can not be classified as a true CO_2 tax: the taxation rate is not related to the external cost of CO_2 and is not applied uniformly neither across industries, nor across fuels (case of fuel use in power generation). Rather than as an elegant market based tool for the achievement of CO_2 reduction targets, it must be classified as a bureaucratic control tool. The Danish Government hopes that its example will accelerate the introduction of CO_2 taxation in other countries. That is not likely. The clumsiness of the scheme reinforces the case of those who argue that CO_2 taxation should be introduced via the adoption of an EU directive. However, there is no doubt that the scheme will make a positive impact towards the achievement of the other objectives of the Danish Government:

* The energy planners expect that the scheme will *encourage energy savings and fuel switching leading to a reduction of CO_2 emissions of 2.8 million tons per year equal to 4.6% of total 1988 CO_2 emissions in Denmark*. The estimate seems to be realistic. The scheme will result in an annual CO_2 and SO_2 taxation revenue of DKK 2.5 billion (US$ 450 million). This increases the cost of energy consumption in Danish industry by 30-40%. In particular, however, the time-limited investment subsidy scheme will generate the savings.. Danish industry like all industries in the world loves subsidies!

* The total revenue from green taxation which on the basis of adopted laws will be levied on Danish industry in the years to come amounts to 10-20% of total wage and salary costs in industry. Some *positive impact on employment* will result from this.