ation to export to South Africa's Council for Scientific and Industrial Research its powerful Cyber 170/750 computer.[14] In principle, this computer might be used to help design nuclear weapons. Later in 1982, the Administration's consideration of a request to export to the Atomic Energy Board of South Africa a small quantity of helium-3, which could theoretically be utilized to produce tritium, an isotope of hydrogen used in thermonuclear weapons,[15] resulted in criticism from both within and outside of Congress. At the time of writing, approval of this export was still pending.

The Administration has reportedly said it has 'adopted a more flexible policy with respect to approvals of exports of dual-use commodities and other materials and equipment which have nuclear-related uses in areas such as health and safety activities'.[16] It argued that improved relations with South Africa were desirable to resolve the Namibian question, and that South Africa had provided assurances that the dual-use items would not be used for non-peaceful purposes. Besides, it was asserted that there are limits to the US ability to control nuclear developments abroad, and that a policy of denial would only diminish such US influence. Critics, however, point to the sensitivity of exports such as the Cyber computer, as well as to the adverse effects that exports with only symbolic significance (eg, helium-3) could have on US efforts to curb the spread of nuclear weapons.

## Implications for US non-proliferation policy

What reasonable inferences can be drawn from statements of the Reagan Administration about the evolution of US policy for nuclear exports, especially in the light of the cases examined? What are the likely implications of this evolution for US policy to prevent the further spread of nuclear weapons?

The Reagan Administration has not, as some have alleged, proposed to overturn all restrictions on US nuclear trade. It has said it will continue the established policy of restricting certain nuclear exports and that it intends to apply the export controls it inherited. It has not proposed they be abolished. Indeed, it has moved to tighten regulations governing DOE authorizations of technology transfers. The Administration says its nuclear export policy approaches the relationship between international nuclear commerce and the spread of nuclear weapons realistically, and can increase US leverage in this sphere. As well, it sees its policies as reducing friction between the USA and its allies, and as improving the health of the US nuclear industry. On the other hand, the Administration's great emphasis upon the reliability of the USA as a nuclear supplier, coupled with its desire to increase US exports generally, have caused some concern that it might put trade considerations ahead of preventing the further spread of nuclear weapons. This concern has been exacerbated by the apparent reluctance of the Administration to use fully what leverage it has, or appeared to have, to influence Brazil and India. Its authorization of some dual-use exports to countries like Argentina and South Africa, its decision to allow export of sensitive technologies to certain countries, and its policies on reprocessing and plutonium use abroad have been seen by some to be eroding US nuclear export controls and adversely affecting long-term US non-proliferation interests.

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# Cogeneration – allocation of joint costs

*In planning district heating projects based on cogeneration, a rule is required to split the simultaneous costs over electricity and heat. This article formally structures the discussion on this issue, and an allocation rule, using the long-run marginal generation costs of the byproduct, is argued to be the best one from a district heating planning viewpoint.*

*Keywords:* CHP; Electricity pricing; Economics

Because of its apparent benefits with respect to energy conservation, supply security, and environmental protection, interest in district heating revived in Europe after 1973. R&D efforts are focused on the economic feasibility of district heating schemes based on the cogeneration of electricity and low-temperature heat.[1] The profitability of a project is very sensitive to the way the joint costs of production are allocated to both outputs. Vigorous discussion arose between electric utilities, public authorities and research units on an exact and practicable way of splitting the costs. This paper tries to structure the debate, but is not impartial since it presents one method as the best.

The framework for the discussion is the planning of large-scale district heating systems in Belgium. In these systems, combined heat and power (CHP) plants provide baseload heat delivering all cogenerated power to the national grid. Only coal-fired, steam cycle plants (back-pressure and extraction-condensing units) are considered because the present and expected future premium on oil and gas excludes these fuels from baseload heat, *viz* electricity generation.

Two approaches are possible to the joint cost problem. First, one can avoid allocation rules by optimizing the production of heat and electricity simultaneously. This procedure requires knowledge of the product transformation frontiers and of the demand functions for both outputs. In the alternative approach the outcome of a simultaneous optimization is approximated by defining a particular allocation rule. The various rules can be distinguished by their need for available information regarding the demand for both outputs.

## Theoretical discussion

In textbooks on microeconomics[2,3,4] it is assumed the demand functions for both outputs are known. Two types of processes are distinguished:

- Cases in which there exists a well defined function between the two outputs,[5] ie the output expansion path[6] is unique. A particular case occurs if the fixed expansion path is linear, in other words if the multiple products are produced in fixed proportions.[7] By defining a compound unit of output the analysis for a single output can be applied.
- Cases in which the products can be generated in variable proportions.

The first case would apply if all power is viewed as back-pressure power. On the other hand, heat extraction is clearly an example of varying the proportions between the two outputs.[8] In a long-run planning perspective the substitution possibilities between heat and electricity generation are definitely large.

The basic economic concepts can be found in Henderson and Quandt.[9] In essence, the theory shows how to derive the equilibrium quantities and prices of both products given a particular production possibility frontier (or product transformation curve) and given the demand functions for both products. The equilibrium values are the ones that maximize or minimize some objective function.

If both products are sold in competitive markets, the firm will operate where the transformation curve is tangent to the highest possible receipts curve, and this is equivalent to equating marginal cost and price.[10]

Monopoly power in one market tends to shift the product-mix towards the output sold in that market. If, for example, the company maximizes the revenue subject to the concave production locus $F^\circ = h(Q,E)$, and holds a monopoly position in the electricity market while the heat market is competitive, the problem of revenue maximization is stated as:

$$\max_{Q,E} L = p_Q \cdot Q + p_E(E) \cdot E + \lambda\{F^\circ - h(Q,E)\}$$

$E$ = electricity production (MWh)
$q$ = heat capacity (MW)
$Q$ = heat production (MWh)
$F$ = fuel input (MWh)
$p$ = prices

From the first-order conditions $\frac{\partial L}{\partial Q} = 0$ and $\frac{\partial L}{\partial E} = 0$, one derives $\frac{p_E}{p_Q}\left(1 + \frac{1}{\varepsilon_E}\right) = -\frac{dQ}{dE}$, where $\varepsilon_E$ is the price elasticity of the demand for electricity ($\varepsilon_E < 0$).

Of more practical interest is the pricing of joint products by public monopolies subject to a budgetary constraint.[11,12] The objective of the public utility is to maximize aggregate welfare, but it has to equalize profits to a given target value. Assuming demand functions and the joint cost function are known, prices should be set as:

$$\frac{p_Q - (\partial C/\partial Q)}{p_Q} = k \cdot \frac{1}{\varepsilon_Q}$$

and

$$\frac{p_E - \partial C/\partial E}{p_E} = k \cdot \frac{1}{\varepsilon_E}$$

with $\varepsilon$ = price elasticity of demand, $C$ = cost function of joint process.

The formula states that the percentage deviation of prices minus marginal costs should be inversely proportional to the elasticities of demand for the goods in question. This means that goods with a very small elasticity of demand should sell at a price much larger than marginal cost, and *vice versa*.

As to the combined production of electricity and low-temperature heat, the derived result shows that cross-subsidization from one product to the other can be a sound policy. During the expansion period of district heating, electricity tariffs would be increased to pay for the district heating costs. This policy is already applied in some existing systems.

Although consideration of the theoretical principles is valuable, their straightforward application in a planning context is impossible since there is inadequate knowledge of future electricity and heat loads and their relationship.

## Practical approach

District heating appraisal studies to date have not undertaken simultaneous optimization of the district heating and electricity generation systems. In most studies the cost of district heating is estimated by applying some allocation principle for the joint generation costs. For an allocation principle to be acceptable it has to be simple – ie easy to apply and to audit – as well as fair and reasonable. A third criterion is that the principle should guarantee that optimal decisions are made.

Most texts emphasize that any allocation rule is arbitrary.[13] The total costs of the joint generation of $E$ and $Q$ can be split in an infinite number of ways (see Figure 1). The coordinates of any point of the isocost line in Figure 1 represent a particular form of alloca-

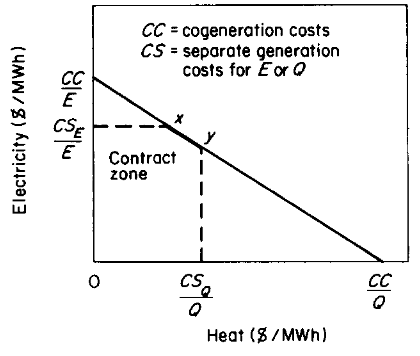


**Figure 1. Allocation of joint costs $CC$ to the outputs $E$ and $Q$.**

tion. Only a subset (still infinite) of this set of pairs is acceptable to both parties involved, and is labelled as 'contract zone' $xy$. The contract zone contains all allocation ratios either to which one of the parties is indifferent (the border points $x$ and $y$), or that benefit both parties (inner points) with respect to independent generation of the product.

The choice of a particular point in the closed $xy$ interval is arbitrary and is related to the definition of one or other product as a byproduct. As to the cogeneration of $E$ and $Q$, one of the two border points $x$ and $y$ is often accepted. If $x$ is selected, all benefits of simultaneous production are assigned to heat (ie electricity is a by-product). For district heating purposes the $x$ standpoint is 'fair and reasonable'. Without heat distribution facilities no waste condenser heat can be recovered. Under present circumstances, analysing the economic feasibility of district heating amounts to examining the benefits of cogeneration as being sufficient to pay for additional investment in heat recovery infrastructure.

The $x$ point is accepted by Belgian power companies. By definition, however, all points within the contract zone $xy$ can be contracted between the $E$ and $Q$ parties.[14] Assuming $x$ is accepted as the contract point, the problem consists of estimating the ordinate of $x$, ie the costs of independent or separate generation of electricity $E$. These costs ($CS_E$ in Figure 1) are the costs that would have been incurred if the same amount $E$, generated in the combined plant if the project is realized, were to be produced with other facilities ('opportunity $E$-generation'). No general agreement on the procedure for measuring $CS_E$, and consequently on the value of $CS_E$, can be found in the literature. The discussion here is limited to three items identified as:

1. Compensation for $E$ production lost by exhausting the steam at a temperature higher than that of the cooling water;
2. evaluation of $CS_E$ as the short-run marginal production cost of separate $E$ production;
3. evaluation of $CS_E$ as the long-run marginal production cost of separate $E$ production.

Because the three allocation principles agree on a point in the $xy$ contract zone, all three are reasonable. The first is simple but lacks incentives to optimize the CHP process. The main drawback of the second principle is that it is very complex to apply, not to say impracticable from a planning point of view. The third principle gives the same cost allocation as the second if the electricity system is in equilibrium. Moreover, it is simple and can be applied in planning studies. In the remainder of this section the alleged characteristics of the three principles and their definition are discussed.

1. By extracting steam at a turbine, part of the electricity capacity of the unit is transformed into heat capacity.[15] A fraction of the electricity, generated if no extraction takes place, is now 'lost'. An allocation rule for joint costs consists of evaluating the lost electricity output and billing that sum to the heat distributor. The district heating company would be relieved of the problems of defining and evaluating the 'opportunity $E$-generation', and only a contract has to be signed, based on contracting experience of utilities and large enterprises, between the electric utility and the company. Clearly, the problem of evaluating the 'opportunity $E$-generation costs' is only transferred from the present study to the bargaining room where the contract has to be drawn up.

Also, the method provides no incentive for the electric utility to provide optimal production units for CHP generation. Because the 'lost' electricity is sold as any other 'normal' kWh, the electric utility has no incentive to change the present design of optimal electric generation. The temperature level of the extracted steam is not optimized, specially designed back-pressure and extraction-condensing turbines will not be installed, etc. The 'lost electricity' rule can be of practical importance if the low-temperature heat is recovered in existing plants, owned and operated by the electric utility. Under these circumstances, no optimization of the cycle is possible, and one only has to fix a price for the lost kWh.

2. Evaluating cogenerated electricity as the short-run marginal costs of the electricity generating system is theoretically consistent, but very difficult to apply. The short-run marginal production cost of an electricity system varies within a year, a week, or a day. Because the $E$-output of a CHP plant depends on the $Q$-load, one needs to know the $Q$-load pattern and its relationship to the $E$-load pattern, ie chronologic load structures of both outputs. Such patterns should be estimated for future decades, depending on the planning horizon. The practical difficulties of doing this cannot, in my view, be overcome, and if the method is used, one needs numerous simplifying assumptions, probably resulting in a method quite different from the one employed theoretically.

Not only both load patterns, but also the present and future structure of the electricity system, and its generation costs, should be known. Here too, it is not easy to find reliable data. In a generation planning study of the Belgian electric system for the period 1982–1995 (with present capacity about 10 000 MW), the yearly expected short-run marginal kWh cost is estimated as 50–130% of its 1981 value, depending on fuel price evolution, load growth and capacity additions.[16]

If all information required were available, the proposal is to substitute the electricity generated in the CHP plants for the production of the marginal units of the $E$-system. This could result in accounting problems if cogeneration were developed on a large scale, because one has to decide which marginal units of the $E$-system are replaced by which units of the CHP system.

In a planning context, the short-run marginal costs allocation method is extremely difficult to realize, and even as a rule for instantaneous allocation, the method involves accounting problems and requires much data.

3. The significance of long-run marginal costs or 'expansion' costs is stressed by Boiteux and Turvey, among others.[17,18,19] In optimally composed power generation systems, short-run and long-run marginal costs are equal for any layer of the load structure (see Figure 2). When marginal capacity $e$ is added with a scheduled operation of $t$ hours a year, all units higher in the load diagram will generate $e \times t$ less power. New capacity will be added only when the fuel cost of equipment in place is higher than the total cost of new equipment in generating $e \times t$.

When considering new commitments, an electric utility will take the lowest of both cost figures as reference. The utility will not be prepared to contract new power on the basis of short-run marginal costs if the long-run marginal costs of supplying this power are lower (as is the case in most systems, including Belgium).[20]

The long-run marginal costs of 'opportunity $E$-generation' consist of capital expenditure for the marginal

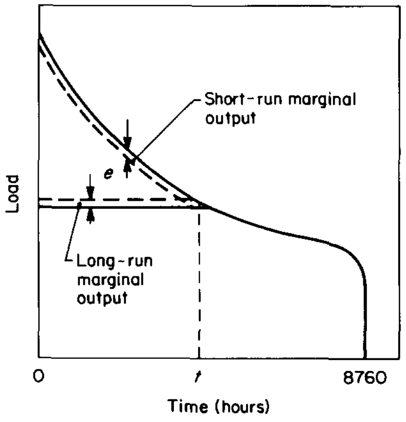


**Figure 2.** Equality of short- and long-run marginal costs in an optimal production system.

capacity installed and outlays to keep that capacity running. It is thus necessary to measure the electricity generating capacity available in the CHP plants, and the amount of electricity generated with it. The capacity of a CHP unit is not constant during the year. Extraction-condensing turbines guarantee a higher capacity when heat load is low than when it is high, because of the substitution relationship of $E$ and $Q$. On the other hand, back-pressure turbines are characterized by a higher electricity capacity when heat load is high than when it is low, because of the complementarity between $E$ and $Q$.[21]

The capacity guaranteed by the CHP production system is the sum of the capacities of the particular units. There is interesting complementarity between back-pressure and extraction-condensing turbines, if the former are placed at the bottom of the load diagram, and the latter immediately thereon. This effect (caused by the opposite characteristics of the two turbine types) requires that back-pressure units are the base-load units in a least-cost planning solution.

Having estimated the electricity capacity of the cogeneration plants during a year, the value of that capacity and the value of the electricity generated has to be agreed. Because that capacity and output will displace separate $E$-generation capacity and $E$-production, one has to define $E$-values from the perspective of the electric utility, which may be summarized as follows:

- *Capacity* – an electricity generating capacity has a value if the utility can call on the capacity at any moment in time, and if the utility can dispose of it when it is no longer needed.
- *Production* – the utility is not interested in buying electricity at a price higher than (or equal to) its own short-run marginal generation costs. The 'equal to' case denotes that an electric utility is founded 'to generate electricity, not to buy it'. At this point in the discussion, electric utilities are often accused of traditionalism, etc, but this kind of argument is not pursued here.

The electric utilities' viewpoint is perfectly logical, and can be used to define 'opportunity $E$-generation' costs. In Belgium, the electric utilities agree on the cost allocation represented by point $x$ in Figure 1. All benefits are allocated to heat, ensuring that cogeneration is a neutral activity with respect to the electricity system. Neutrality is attained if electric CHP capacity is equally guaranteed as condensing capacity, and power is brought into the grid at a price equal to the marginal fuel cost of the reference condensing unit.

Guaranteed electric capacity is equal to the expected value of the minimum over time of the sum of CHP electric capacities. This minimum can occur in winter when extraction-condensing capacity is preponderate, or in summer when back-pressure capacity is preponderate. This minimum capacity is available during any hour of the year and is thus baseload electric capacity.

The minimum guaranteed electric capacity of the combined system is rated as new baseload capacity in the generating system. All capacity available above this minimum during some periods of the year is called 'wild'. Wild capacity is not compensated, and may be seen as providing fortuitous benefits to the electric utility if it can be integrated the moment it is available.

Table 1 summarises characteristics of baseload powerplants and CHP plants. Assume, for example, that a 250 $MW_e$ extraction-condensing CHP plant is installed, requiring investments of \$160 million (= 250 $MW_e$ × \$640/$kW_e$). At maximum heat load on the CHP turbine, 40 $MW_e$ is 'transformed' into heat capacity. Consequently, at least 210 $MW_e$ is available whatever the heat load may be. After correcting for outage time the expected guaranteed capacity is 176.4 $MW_e$ (210 $MW_e$ × 0.84 disposability). One can value this capacity as coal baseload capacity (176.4 × (\$540/$kW_e$/0.78 disposability) = \$122 million), or as nuclear capacity (176.4 × (\$1000/$kW_e$/0.74 disposability) = \$238 million).

By compensating guaranteed CHP capacity as baseload capacity, one defines the power produced from the CHP process as baseload electricity – ie the value of a CHP kWh equals the fuel cost of the reference baseload station

**Table 1. Power plant characteristics (average magnitudes for Belgium, 1981).**

| | Baseload new condensing stations | | CHP steam cycle plants (coal-fired) | |
|---|---|---|---|---|
| | Coal | Nuclear | Back-pressure | Extraction condensing |
| Power range ($MW_e$) | 600 | 1300 | 60–120 | 120–250 |
| Expected disposability (%) | 78 | 74 | 88 | 84 |
| Efficiency (%) | | | | |
| Cold-condensing | 38 | 32 | – | 36 |
| Maximum heat load [a] | – | – | 86 | 82 |
| electricity | – | – | 30 | 32 |
| heat | – | – | 56 | 50 |
| Costs [b] | | | | |
| Investment ($/$kW_e$) | 540 | 1000 | 610–590 | 690–640 |
| Staff + maintenance ($/$kW_e$–y) | 16 | 26 | 26–17 | 20–17 |
| Fuel (mills/$kWh_e$) | 21.08 | 8.45 | – | – |

[a] For details, see reference 8.
[b] $1 = 40 Belgian francs (1981).

kWh (21.08 mills/kWh for a coal-fired plant and 8.45 mills/kWh for a nuclear plant). When bargaining, the proposed procedure may be used more flexibly, for example by considering planned and forced outages separately or by measuring guaranteed CHP capacity month by month.

The benefits of the proposed allocation principle are substantial. First, it is very simple to understand and to implement. For implementation, one only needs to know the capital and operating costs of today's generating technologies. Second, the principle is well suited to project planning studies. New investments are made in CHP plants and in electricity plants, and the capacity and output of both types are evaluated by the same standards.

This is an important point. In district heating systems (ie CHP output is baseload production), only coal-fired steam cycle plants of adequate scale are economically feasible. When the proposed procedure is used, CHP fuel cost and revenue from cogenerated power are correlated, guaranteeing the profitability of the CHP process in the long run. On the other hand, the economics of gas- or oil-fired CHP systems may become troublesome by diverging input prices and revenue from outputs.

Third, no detailed assumptions with respect to the synchronism of heat and electric loads and with respect to the capacity of both energy grids are required. All electricity from the cogeneration process enters the electric system at a price equal to or lower than the short-run marginal costs of the electricity generation system. As a corollary, it is possible to decentralize the decisions on district heating production plants towards the districts concerned. With communication between the $E$ and $Q$ producer, and because capacities are guaranteed, double investments can be avoided. The principle allows the least-cost district heating configuration to be determined while ensuring optimal planning of the electric system.

The assumptions underlying the allocation principle are plausible. The demand for electricity has to expand over time to be able to integrate the electric capacity from the CHP plants into the base of the electric load diagram.

The allocation resulting from the rule can be acceptable to the electric utilities because the electricity system is not in principle affected by the construction of cogeneration plants. Some benefits and costs of the integration of combined capacity are not discussed here. Benefits include the wild capacity above the minimum (and paid for) capacity, available during some periods of the year. Second, the reliability of the production system is enhanced because capacities are provided in smaller units, spread over the country. This spreading of units, and their location next to electric load gravity centres, reduces the pressure on the electricity transmission capacity. These benefits are offset partly by the increased intricacy of operating the electric system.

## Conclusion

It is argued that simultaneous optimal planning of CHP in district heating and electricity production systems is difficult to realize because of lack of reliable information on the demand for heat and electricity.

In practice, district heating generation costs are minimized ensuring that the introduction of cogeneration turbines is a neutral activity for the electric utilities. Therefore, the cogenerated electricity should be billed at the costs incurred if the 'same' electricity were produced elsewhere.

In a planning context, the above principle is approximated best when using the long-run marginal costs of the electricity system as transfer prices – ie the electric capacity and the electricity production of combined turbines are evaluated as capacity and production of the electricity-only plants that the utility would install if no cogeneration was available.

The discussion above is not intended as the last word on the complicated issue of joint cost allocation. However, the analysis allows the discussion to be continued along well defined principles.

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# Conference reports

## Nuclear power experience

IAEA International Conference on 'Nuclear power experience', *Vienna, 13–17 September 1982*

In virtually all countries outside the Eastern bloc there has been a major reduction in the rate of installation of nuclear power plant, with the result that the projected amount of nuclear power available by the year 2000 has dropped from 2000 $GW_e$, estimated in 1977, to about 900 $GW_e$, estimated in 1981. The IAEA's 'Nuclear power experience' conference provided an excellent opportunity for the nuclear industry and its critics to consider the reasons for this decline in the industry's fortunes.

On the whole the industry still seemed to be quite optimistic about the future but, as discussed below, it may have failed to diagnose fully the reasons for its decline and may find that recovery of the market for thermal reactors may take longer than currently expected and that the date at which exploitation of the breeder reactor takes place on a commercial scale is further away than has been supposed previously.

In his opening address, Dr Eklund, former Director General of the IAEA, suggested that the main reasons for the decline in the rate of growth of nuclear power were as follows:

- the reduction in energy demand due to the general recession;
- the increase in energy prices, leading to greater emphasis on energy conservation and a further reduction in demand;
- in some countries, a general reaction against complex, large-scale enterprise;
- fear amongst members of the public about nuclear safety and the hazards arising from nuclear wastes.

The papers presented at the conference, together with the discussion, provided support for these views but there appeared to be some reluctance on the part of the nuclear industry to realize that some of the problems were due to its own shortcomings.

There was, for example, a tendency to attribute most of the reduction in the rate of installation to the recession and to increases in cost due to delays arising from the licensing process. However, it might well be asked whether the predicted rates of installation in the developed countries were realistic in the first place. In retrospect the forecasts of growth in demand for electricity seem to have taken insufficient account of changes in the pattern of the world economy which has led to a shift of the traditional heavy, energy-intensive industries from the developed countries to some of the developing countries (Korea for example is now producing at least as much steel as the UK, whereas since 1970 UK output has fallen from 28 million to about 10 million tonnes per year); at the same time a larger proportion of the GNP of the developed countries is being derived from high technology industries which are less energy intensive.

A further cause of the reduction in growth rate of nuclear power is the changing age-structure of the plant on most systems; whereas in the last decade most systems still carried a substantial amount of small, old plant of low thermal efficiency this has now largely been scrapped, so that the least efficient fossil-fired plant is not much less efficient than the newest plant of that type. Consequently there is now more incentive to refurbish the older plant, rather than to replace it with new, which might have been nuclear.

In Europe, Japan and the UK the rapid increase in the share of the total energy market taken by natural gas and LPG has diminished electricity's share in some sectors, notably domestic heating and cooking.

Although the claim was made in several papers that, in many countries, nuclear power is a cheaper means of generating electricity than by using fossil fuel, there was little analysis of why utilities are deterred from ordering nuclear plant in preference to fossil fired. For example:

- The Three Mile Island accident has demonstrated to utilities, and their insurers, the very high cost of such an occurrence; in a recent article in *Energy Policy*[1] it was suggested that the economic consequences of this type of accident could give a surcharge on PWR capital costs of 7.5%.
- In those countries where electricity generation is mainly carried out by private enterprise, subject to close government control, it has become apparent to investors that