Complaints on Bidding Practices in the Single Electricity Market

SEM COMMITTEE INQUIRY

Final Report

SEM-08-069

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Table Of Contents

Acronyms

AIP	All Island Project
BCOP	Bidding Code of Practice
CADA	Capacity and Differences Agreement
CHP	Combined Heat and Power
CPM	Capacity Payment Mechanism
EPA	Environmental Protection Agency
ESB	Electricity Supply Board
ESBI	ESB International
ESB PG	ESB Power Generation
GJ	Gigajoule
GT	Gas Turbine
GSA	Gas Supply Agreement
MO	Market Operator
MSP	Market Scheduling & Pricing
MW	Megawatt
NI	Northern Ireland
NIE	Northern Ireland Electricity
O&M	Operations & Maintenance
PPB	Power Procurement Business
PPL	Premier Power Limited
PQ	Price Quantity
ROI	Republic of Ireland
SEM	Single Electricity Market
SMP	System Marginal Price
SRMC	Short Run Marginal Cost
SO	System Operator
TSC	Trading & Settlement Code
VOM	Variable Operations & Maintenance
VPE	Viridian Power & Energy

1. Introduction

1.1. Soon after the start of the Single Electricity Market (SEM) on 1st November 2007, several participants expressed concern to the Commission for Energy Regulation and the Northern Ireland Authority for Utility Regulation (the "Regulatory Authorities") about the bidding strategies being undertaken by other participants. These culminated in the submission of official complaints by Premier Power Limited and Viridian Power and Energy alleging that bids submitted by ESB Power Generation, ESB International, Huntstown, Synergen and Tynagh Energy were not in compliance with the obligation in their Licences to submit cost reflective commercial offer data.

1.2. These complaints were considered by the SEM Committee and a formal inquiry initiated. This first involved requiring generators to give reasoned explanations of how commercial offer data were calculated. Subsequently all interested parties were given the opportunity to make formal oral and written submissions to a sub-committee appointed by the SEM Committee to consider this matter.

1.3. During the course of this inquiry, the SEM Committee engaged extensively with complainants and those against whom complaints were made. Based on the information it received and its own analysis of the issues involved, including a review of relevant legislation, Licences and codes, the SEM Committee has formed its decisions on the merits of the complaints and the requirements of the relevant Licence conditions.

1.4. This report is organised as follows:

- Section 2 sets out the background to the inquiry;
- Section 3 summarises the complaints;

- Section 4 sets out the process followed by the SEM Committee in conducting its inquiry;
- Section 5 discusses the relevant Licence condition and the relevant parts of the Bidding Code of Practice;
- Section 6 sets out the main issues relating to the commercial offer data submitted by Coolkeeragh, Moneypoint and Poolbeg;
- Section 7 considers the main issues relating to commercial offer data submitted by Synergen and Tynagh Energy;
- Section 8 sets out the SEM's duties, against which its decisions on these various matters are made;
- Section 9 discusses the interpretation of the cost-reflective Licence condition and the Bidding Code of Practice with respect to the costs of repeated starts and gives the SEM Committee's decision;
- Section 10 discusses the opinion of the SEM Committee on the complaints made about the bidding behaviour of Synergen and Tynagh Energy and gives the SEM Committee's decision;
- Section 11 discusses the commercial offer data relating to the operating parameters of ESB PG plant (Moneypoint and Poolbeg) and gives the decision of the SEM Committee;
- Section 12 presents a summary and decisions.

2. Background

2.1. This section provides an overview of the key relevant features of the SEM, which include:

- a mandatory gross pool;
- day-ahead complex bidding;
- ex-post system marginal price (SMP) pricing (which excludes transmission, reserve and other constraints), with a single island-wide price for each half hourly trading period;
- central dispatch; and
- a separate capacity payments mechanism.

2.2. Participation in the pool is mandatory for licensed generators and suppliers, save for generators which have a maximum export capacity of less than 10MW (the *de minimis* threshold) for whom direct participation is voluntary. As a result, almost all electricity generated has to be sold into and purchased from the pool.

2.3. Under the pool trading arrangements, the sale and purchase of electricity is conducted on a gross basis, with all generators and suppliers receiving and paying the same price for the electricity sold into and bought from the pool.

2.4. Participants are required to submit offers into the pool in respect of each of their generator units for each trading day. The data contained within offers apply equally for all trading periods within the relevant trading day. Offers must be submitted by gate closure, which is at 10am on the day before the relevant trading day (which begins at 6am the following calendar day).

2.5. Offers consist of commercial offer data and technical offer data. Technical offer data relates to the technical capabilities of the generator unit and consists of parameters such as ramp rates. Standard commercial offer data consist of:

- one no load cost, which is the element of operating costs which is invariant with the actual level of output;

- a minimum of one and a maximum of three start up costs, which reflect the costs associated with starting up the generator unit from cold, warm or hot states; and

- a minimum of one and a maximum of ten price quantity (PQ) pairs, each of which sets out a quantity up to and equal to which the associated price applies. PQ pairs must be strictly monotonically increasing with only one price for each quantity. PQ pairs are bounded, in terms of quantity, by the minimum output at the lower end and actual availability of the generator unit at the upper end.

2.6. Under these pool arrangements all generator units receive and all supplier units pay the same energy component of the price in a trading period for electricity. This is the system marginal price (SMP). The SMP is determined by the market scheduling and pricing (MSP) software, which is run by the market operator.

2.7. The MSP software is used to calculate after the event:

- the SMP for each trading period; and

- the market schedule quantity (being the quantity of output scheduled by the MSP software) for each price maker generator unit for each trading period, ignoring transmission constraints and reserve requirements (i.e., assuming an unconstrained schedule).

2.8. The MSP Software runs for an optimisation time horizon, which is a 30 hour period. It seeks to identify the lowest cost solution at which price maker generator units provide sufficient generation in each half hour to meet demand that is not met by price taker and autonomous generators. It calculates the SMP in each half hour to:

- reflect the cost of the marginal MW required to meet demand in a trading period within the context of an unconstrained schedule; and

- recover operating costs associated with start up costs and no load costs.

2.9. Under the SEM, dispatchable generator units are dispatched centrally by the system operators (SOs), rather than autonomously through self-dispatch by the individual generators (as would be the case in a non-centrally dispatched market). As for the market schedule determined by the MSP software, actual dispatch patterns are in principle based upon economics, and it is a reasonable expectation that the cheapest generation will be scheduled to run first, whilst respecting the technical capabilities of the generator units.

2.10. However, while the MSP software produces a market schedule on the assumption of an unconstrained system, ignoring the impact of, for example, transmission constraints, voltage and reserve requirements, the SOs must dispatch generators taking system constraints and reserve requirements into account. They must also consider real-time issues on the system such as forced outages. The actual dispatch schedule followed is therefore likely to deviate from the market schedule produced by the MSP software.

2.11. While SMP pricing ensures that the pool price reflects the value of energy in any half hour, the capacity payment mechanism attaches a value to the provision of capacity within the market. Generators get paid a capacity payment on the basis of their availability in each half hour. Capacity payments are funded by capacity charges, which are levied in respect of suppliers based upon their electricity consumption. The capacity payment mechanism is intended to strike a balance between providing the highest capacity prices at periods of highest loss-of-load probability to value the provision of capacity appropriately, and providing a stable set of investment signals.

2.12. This particular market design (comprising a gross mandatory pool, central dispatch, complex bidding, a separate capacity payment mechanism etc.) was chosen by the Regulatory Authorities after an extensive consultation process.

2.13. A gross pool was considered particularly suited to the needs of the SEM, as it was thought more likely to provide both the economic signals and the price discovery to encourage timely entry of new generation and the certainty of generation source to encourage new supplier entry. The model was also recognised as being more suitable for the participation of renewable and CHP generators, since all energy could be sold directly to the pool and off-take contracts were not a prerequisite to market entry. Transparency is a key feature of the design of this market.

2.14. Central dispatch/commitment was chosen over self dispatch because it was thought more suitable for the SEM in terms of cost and effectiveness, practicality and security of supply.

2.15. While complex bidding was not explicitly chosen for market power mitigation reasons, it was subsequently recognised that the requirement on generators separately to bid no load and start up costs and PQ pairs would be of significant assistance in the monitoring of generator bidding behaviour in the SEM.

2.16. Finally, a separate capacity payment mechanism was chosen on the basis that it would offer greater stability and security to the market - and thereby consumers - than an energy only market. An energy-only market would require price spikes in a small number of hours each year to ensure revenue adequacy. Given the capacity payment mechanism, there is no reason why SMP should rise above the short run marginal cost (SRMC) of the marginal generating set in order to induce sufficient entry into the market.

2.17. Avoiding the double payment of generators for capacity, together with the need to mitigate market power, led the Regulatory Authorities, after consultation and extensive discussion with interested parties, to put conditions in generators' Licences requiring cost reflective bidding and to establish a Bidding Code of Practice (BCOP) under those Licences.

2.18. Both the Licence and the BCOP establish the principles to be followed by the market participants when submitting commercial offer data. The aim is to clarify the competitive behaviour that is expected from market participants so that they do not try to structure their bids to maximise short term commercial positions to the detriment of customers and other market participants.

3. The Complaints

3.1. Viridian Power and Energy (VPE) and Premier Power Limited (PPL) officially complained to the Regulatory Authorities on 23rd November 2007 and 27th November 2007 respectively about the bidding behaviour of certain generators during the first few weeks of the operation of the SEM. The complaints arose out of the emergent 'two-shifting' of several hitherto baseload plant in the market schedule. 'Two-shifting' refers to the case in which a plant is operated at full (or close to full) output during periods of high demand (i.e. during the day) and shut down during low load periods (i.e., at night), in a continuing daily cycle. This scheduling pattern, which emerged after 1st November 2007, did not align with the experience of pre-SEM dispatch patterns.

3.2. Subsequent to the consideration of these complaints by the SEM Committee, AES Kilroot, Airtricity and NIE Energy's Power Procurement Business (PPB) wrote to the Regulatory Authorities setting out concerns about bidding behaviour similar or identical to those set out by VPE and PPL. These complaints are reproduced, along with the complaints by VPE and PPL, at Annex 1.

3.3. The general concern expressed in the complaints was that particular generators had not reasonably interpreted their Licence conditions and the BCOP; and had structured their commercial offer data to ensure that they avoided being two-shifted. Consequently, according to the complainants, costs were being unfairly imposed on other participants who were required as a direct result to two-shift in the unconstrained market schedule.

<u>Viridian Power & Energy's Complaint</u>

3.4. Based on an analysis of market data released in mid-November 2007, VPE alleged that the commercial offer data of Dublin Bay (owned by

Synergen, a subsidiary of ESBI), Coolkeeragh (owned directly by ESBI) and Tynagh were inconsistent with the BCOP, in particular with regards to the content of their PQ pairs. VPE argued that this bidding behaviour led to the non-economic and inefficient dispatch of plants, which adversely affected the security of supply of other plants that consequently experienced excessive two-shifting.

<u>Premier Power Limited's (PPL) Complaint</u>

3.5. PPL's complaint related to the apparent departure of Moneypoint and Poolbeg (both owned by ESB Power Generation), Dublin Bay, Huntstown and Tynagh from the principle of cost reflective bidding. PPL identified a number of specific instances where it believed there was an inconsistency in the commercial offer data of these plants relative to other similar plant on the system.

3.6. The particular points raised by PPL were:

- Moneypoint's start-up costs were ten times those of Kilroot whereas the start-up energy ratios established by KEMA differed by no more than a factor of six;[1]

- Poolbeg's start-up costs were particularly high and unreflective of KEMA's estimates of the start up energy requirement at Poolbeg. Moreover, Poolbeg's start-up costs doubled on 4th November and increased further on 12th November. PPL could not see how these changes accorded with the BCOP;

- Huntstown's start up costs moved with changes in those submitted by Poolbeg, symptomatic of competitive bidding;

[1] KEMA Ltd. was commissioned by the Regulatory Authorities in early 2007 to provide a validated model accurately to predict prices in the SEM. A key part of this work was the validation of generator technical data. Comparisons were made by a number of interested parties during the course of this inquiry to discrepancies between KEMA's validated data and what some participants were using to formulate their commercial offer data.

- Coolkeeragh's start-up costs did not correlate with the energy requirement for the plant;

- Dublin Bay's and Tynagh's start-up costs were unchanged over the period in question, despite contemporaneous movements in the market price of gas;

- Huntstown's no load costs appeared high and inconsistent with the relative no load energy requirements in KEMA's validated database;

- Poolbeg's no load cost data were similarly inconsistent with KEMA's estimates;

- Dublin Bay's and Coolkeeragh's incremental costs (as reflected in their PQ pairs) were below the levels suggested by market gas prices; and their costs did not follow movements in gas prices. The reason for this, PPL maintained, was to reduce the likelihood of the plant being two-shifted.

4. The SEM Committee's Inquiry Process

4.1. The complaints were examined in accordance with published procedures relating to formal complaints (see AIP/SEM/07/511) and considered by the SEM Committee at its November 2007 meeting. After review of the complaints and of the market data available, the SEM Committee decided that the complaints raised issues which warranted further inquiry. This was announced publicly on the AIP website on 4th December 2007 (AIP/SEM/07/01).

4.2. The parties named in the complaints, as well as the complainants themselves, and, in a number of cases, generators with units operating at baseload, were asked to provide an explanation of how they had constructed their commercial offer data in the period since 1st November.

4.3. At this point in its inquiries the SEM Committee was satisfied the COD submitted by VPE for its Huntstown plants did not warrant further investigation. The responses provided were well reasoned and evidenced and indicated compliance with their Licence obligations.

4.4. Based on its initial analysis of the information provided, the SEM Committee circulated a draft report in February 2008 setting out the basis for the observed bidding patterns and its views on compliance of those bids with the cost-reflective Licence condition and with the BCOP. The SEM Committee invited both complainants and respondents to provide their views on this draft report. The SEM Committee then appointed a sub-committee to hear oral representations from the parties.

4.5. While lengthy, the SEM Committee is of the opinion that this process was necessary to ensure that all relevant views were fully taken into account.

5. Licence Obligations and the Bidding Code of Practice

5.1. This section of the report sets out the relevant Licence condition and the relevant parts of the Bidding Code of Practice.

<u>Licence Obligations</u>

5.2. The Conditions in the Irish and Northern Irish generator Licences and in NIE Energy's Power Procurement Business (PPB) Licence require that commercial offer data submitted to the market operator in respect of a generation unit is cost reflective and is equal to the short run marginal cost of that generation unit in respect of the trading day to which the commercial offer data relate.

5.3. Paragraph 3 of the relevant conditions (Condition 15 of the ROI Licence and Condition 17 of the NI Generator Licence and Condition 57 of PPB's Licence) reads:

> *"… Short Run Marginal Cost related to a generation set in respect of a Trading Day is to be calculated as:*
>
> *(a) the total costs that would be attributable to the ownership, operation and maintenance of that generation set during that Trading Day if the generation set were operating to generate electricity during that day;*
>
> *minus*
>
> *(b) the total costs that would be attributable to the ownership, operation and maintenance of that generation set during that Trading Day if the generation set was not operating to generate electricity during that day,*

the result of which calculation may be either a negative or a positive number."

5.4. Thus the costs associated both with operating and with not operating on a particular day are relevant to the calculation of short run marginal cost.

5.5. Paragraph 4 of the relevant Condition states that:

"… the costs attributable to the ownership, operation or maintenance of a generation set shall be deemed, in respect of each relevant cost-item, to be the Opportunity Cost of that cost-item in relation to the relevant Trading Day."

Opportunity cost, the calculation of which is defined in the BCOP, covers any costs attributable to the generation of electricity.

<u>Bidding Code of Practice</u>

5.6. The BCOP defines opportunity cost as comprising:

"… the value of the benefit foregone by a generator in employing that cost-item for the purposes of electricity generation, by reference to the most valuable realisable alternative use of that cost-item for purposes other than electricity generation."

5.7. Paragraph 8 of the BCOP then goes on to require that:

"… where there exists a recognised and generally accessible trading market in the relevant cost-item, the Opportunity Cost of that item should reflect the prevailing price of the cost-item, which may be for immediate or future delivery or use…"

It also allows reasonable provision for risk to plant and equipment from the operation of a unit at Paragraph 8 (iii):

“Reasonable provision for increased risks to plant and equipment as a result of the operation of a generation set or unit may be included.”

5.8. However, if it can be demonstrated to the satisfaction of the Northern Ireland Authority for Utility Regulation or the Commission for Energy Regulation (as appropriate) that there is good cause not to follow the principles set out in paragraphs 8 (i) through 8 (iii), a generator need not calculate the value to reflect prevailing prices on a recognised and generally accessible trading market:

“In calculating the value of the benefit foregone in employing a cost-item for the purposes of electricity generation, the following principles [i.e., 8(i) through (iii)] shall, unless it can be demonstrated to the satisfaction of the Authority or the Commission (as appropriate) that there is good cause not to, be applied.”

6. Start Up Costs

6.1. This section of the report sets out the arguments related to the bidding of start up and no load costs and PQ pairs by Coolkeeragh, Moneypoint and Poolbeg.

6.2. Interested parties were invited to make oral and written submissions to the SEM Committee subsequent to the SEM Committee's initial draft report, which was sent to interested parties in February 2008. AES Kilroot, Airtricity, Coolkeeragh, PPB, PPL and VPE took up the invitation. Their submissions in respect of the issues raised by:

- the bidding by Coolkeeragh of its start up costs and PQ pairs; and
- Moneypoint's and Poolbeg's start up and no load costs

are summarised in this section.

<u>Coolkeeragh</u>

6.3. **Coolkeeragh** set out the following information in relation to its commercial offer data:

- Coolkeeragh's commercial offer data was built up from the fuel cost and variable operations and maintenance (VOM) costs;
- VOM costs were incorporated in start-up and no load costs and PQ pairs;
- start-up costs included loss in available capacity revenue due to increased forced outages associated with the repeated starts of the gas turbine, along with VOM elements;

- the first PQ pair (i.e., that which sets the price for increments in output up to the plant's minimum stable level of generation) was reduced to reflect the opportunity costs of two shifting the plant;

- this opportunity cost included the revenue lost as a result of taking the plant out for a compressor blade inspection.

6.4. Coolkeeragh maintained in their submissions that two-shifting imposed real costs on the plant. These costs included those resulting from an increased risk to the plant from the decision to start the plant. Coolkeeragh were of the opinion that this cost was expressly allowed for in the BCOP.

6.5. Coolkeeragh stated that it now had to undergo expensive inspections after a relatively small number of starts or a defined number of running hours, whichever occurred first. Not only did these inspections impose direct costs on Coolkeeragh; they also resulted in foregone revenues (from both capacity payments and SMP) as a result of increased maintenance outages. Both elements represented an opportunity cost of repeated starting to Coolkeeragh.

6.6. Coolkeeragh accepted that some units will inevitably need to two-shift in the SEM, but contended that this mode of operation has a relatively higher opportunity cost to Coolkeeragh. This was a result of the particular circumstances associated with their plant and the technical difficulties which have arisen since it was commissioned. This meant that Coolkeeragh was required under its maintenance contract with the plant manufacturer to undertake extensive inspections after a relatively few number of starts. Allowing the plant to two-shift on a regular basis would amount purposefully to reducing availability to the system and knowingly placing the plant at risk of damage in such a way as to jeopardise the security of supply and thus place Coolkeeragh in breach of the Grid Code requirement of signatories to act as Reasonable Prudent Operator..

6.7. Coolkeeragh developed their bidding strategy to best manage this risk. They maintain their bidding has been at all times compliant with both the letter and the spirit of the Bidding Code of Practice. Coolkeeragh argued that the risks associated with the operation of plant were explicitly allowed for in the Bidding Code of Practice when calculating opportunity costs.

6.8. Coolkeeragh believed their duty as a reasonable and prudent operator meant that they were compelled to reflect the opportunity costs of repeated starts in the PQ pairs to properly reflect the costs of operation of the plant. Coolkeeragh modelled the operation of the plant in the SEM before the SEM began. This indicated that the discounting of their first PQ pair was the preferable way of reflecting the costs of operation. An increase in their start up costs to a suitable level was an alternative way of reflecting opportunity costs but Coolkeeragh argued that this would

- result in higher costs to the consumer relative to their preferred alternative of a discount on their first PQ pair;
- place undue risk of damage on the plant, potentially resulting in another catastrophic failure such as that suffered in 2007;
- jeopardise system security and deplete Coolkeeragh's capability to respond to system signals; and
- be contrary to Coolkeeragh's obligation under the Grid Code to operate the plant in a reasonable and prudent manner.

6.9. **AES Kilroot** argued that while competition should in principle incentivise participants to avoid deviations in their commercial offer data with respect to their actual costs, the ownership structure of Coolkeeragh means that they are operating under reduced risks. If discounting PQ pairs was used to avoid two-shifting rather than as a reflection of true cost, it sent out the wrong signals to the market.

6.10. The BCOP was developed as an important safeguard against market dominance. It should be applied with a vigorous approach and dominant players need to be tightly regulated to protect against any potential predatory pricing.

6.11. **PPB** expressed concern at the prospect that the SEM Committee could endorse the accounting for risk associated with shutting down or not running in reduced PQ pairs. This would not be reflective of true costs. It would also discourage potential investors if bidding was kept artificially low. Increased risks for potential investors as a consequence might have an effect on security of supply.

6.12. The fundamental market design of the SEM was merit order dispatch, reflective of true costs so that the most efficient plant runs. To meet the requirements of the market design, generators must bid in objectively determined costs that could be measured. To allow bidding to operate otherwise would introduce an arbitrary element to the market that was not desirable.

6.13. The SEM design was chosen in part in the light of dominance; and the BCOP is one of the protections for smaller participants and new entrants. Interpreting the BCOP to facilitate below cost bidding created a risk of predatory pricing.

6.14. Bidding should avoid sustaining inefficiency. High operating costs and risks needed to be considered in investment cost and mitigated by the way in which daily bids are structured. Reducing PQ pairs did not encourage efficiency.

6.15. **Premier Power Limited (PPL)** argued that, as a result of the unique attributes of SEM, (e.g., size and dominance) it must, of necessity, be a managed market. This was recognised during the design of the SEM and was why it had been successfully implemented.

6.16. Cost reflective bidding was a legal obligation, not just a general principle. It applied to all participants. This allowed the bidding system to be clear and transparent. Allowing generators to bid PQ pairs below the operating costs of generators would allow dominant undertakings to shift the market to their advantage. This would increase the risk for new entrants and would destroy the credibility of the ESB divestment programme, further entrenching the position of ESB.

6.17. **Airtricity** argued that the bidding Principles reflected in the BCOP must be based on achieving long term equilibrium in the SEM. This was a fundamental part of the market design. It was inappropriate to minimise losses in short term. Exceptions could not be made or there would be no encouragement for flexibility.

6.18. Any costs associated with starting a plant should be included in start up costs. PQ pairs should not reflect the costs of repeated starts. Bids should be objective so that there was some way of checking bidding practice through audits. Bids should not account for foregone revenues as a result of forced outages resulting from two-shifting.

6.19. There must be transparency within the bidding procedures to avoid potential abuse. This was of particular concern where market power was an issue.

6.20. The market should encourage flexibility and incentivise correct behaviour. In a pool, the scheduling software needed to see the true costs to minimise costs to the customer. Including foregone market revenues in bids could cause distortions.

6.21. **Viridian** argued that the SEM was a small market and must be managed to achieve competitive outcomes. The BCOP served this function and protected the interests of smaller participants and potential new entrants.

Keeping plants operating overnight by bidding reduced PQ pairs meant the market was not necessarily running the most efficient plant.

6.22. Reflecting costs associated with repeated starts could reduce SMP and create a vicious circle of lower bidding and unrecovered costs. This would depress the market, discourage new investment and undermine competition.

6.23. Coolkeeragh's bids had resulted in a lower SMP than would have been the case had they bid higher start up costs. Allowing this bidding to continue also created the perverse situation where inefficient plants with high start up costs were allowed to run continuously at the expense of more efficient plants. This would not give the right signals to plant to re-fit to become more flexible.

<u>Summary</u>

6.24. Summing up, the arguments presented by interested parties in favour of an interpretation of the BCOP which allows generators to reflect the costs associated with repeated starts (insofar as they are allowable) in their PQ pairs (as opposed to start-up costs) are that:

- two shifting increases the risk of plant and equipment failure;
- this risk is explicitly covered in the BCOP's definition of opportunity cost;
- the costs associated with two-shifting can best be avoided by bidding appropriate commercial offer data;
- the desired effect on the running regime of a plant can be achieved either through the bidding of higher start up costs or through the bidding of a lower initial PQ pair;

- a higher start up cost will result in higher market prices, other things being equal, than bidding a lower initial PQ pair;

- bidding a lower initial PQ pair is not without its risks, since the plant will not recover its fuel and other direct operating costs from the market whenever it sets SMP;

- bidding to ensure the baseload operation of an inflexible plant with technical problems such as Coolkeeragh is the least cost approach to achieving system security in the longer term.

6.25. The main arguments against reflecting the costs of two-shifting in a lower initial PQ pair can be summarised as:

- the SEM is by necessity a managed market and this is the basis for its success;

- reflecting the costs of two-shifting in a lower PQ pair:

  - conflicts with the design of the SEM, the aim of which is to ensure efficient centralised dispatch and has provided for the declaration of any start-up costs in the complex bids;

  - risks facilitating predatory pricing;

  - deters new entry by distorting the economics of inflexible plant;

- wear and tear costs associated with repeated starts should be reflected in start-up costs;

- the estimation of foregone revenues was inevitably subjective and such costs should be disallowed on the grounds that they were impossible to audit.

<u>Moneypoint and Poolbeg</u>

6.26. In its submissions to the SEM Committee subsequent to the initial draft report, **PPL** reiterated the points it had raised in its initial complaint about the commercial offer data submitted by ESB PG for Moneypoint and Poolbeg. In particular they argued that the technical and engineering information underlying the calculation of ESB's commercial offer data should be subject to detailed scrutiny.

7. Contract costs

7.1. In their responses to the questions raised during the course of this inquiry **Synergen** stated that

- all commercial offer data was built up from fuel cost and variable operations and maintenance (VOM) costs;
- VOM costs are built into start-up and no-load costs but not into the PQ pairs;
- no adjustment was made for repeated-start risk; and
- the price of gas was based on Synergen's gas supply contract, not on the market price of gas.

7.2. Synergen made reference to its Gas Supply Agreement (GSA) in determining the relevant opportunity cost of the gas used in generation. Synergen have based their commercial offer data on their contract price arrangements for gas rather than the market price. This has led to the price of each of Synergen's PQ pairs being significantly less than that of other gas fuelled generators. Start-up and no-load costs are also significantly lower than those of other similar units.

7.3. Synergen's bids for Dublin Bay were based on gas prices which are low relative to market prices. Synergen argued that in terms of the GSA, they do not have title to gas and, consequently, it is not possible to resell the gas. Synergen argued that this had the effect of making the national balancing price (NBP) for gas irrelevant in their calculations. The contract price for fuel, which they would pay for any gas consumed, was therefore the opportunity cost to Synergen. This, it was argued, was the benefit foregone by Synergen.

7.4. Synergen accepted that, theoretically, all contracts could be renegotiated to reflect their intrinsic value. However, their view was that the transactions costs associated with any attempt to renegotiate the GSA would be such that they would eliminate potential benefits to Synergen.

7.5. While Synergen did not believe that they would currently operate at a loss were they to bid in at prevailing market prices, as they believed their plant was one of the most technically efficient on the system, they thought that bidding the market price of gas would have a significant and negative impact on their longer term profitability. On the issue of the need to encourage efficiency in the market, Synergen pointed out that there were two forms of efficiency - technical efficiency and economic efficiency - and that their low price contract was enabling Dublin Bay to operate at a high level of economic efficiency.

7.6. In their responses to the questions raised as a result of this inquiry, **Tynagh** argued that

- PQ pairs were initially constructed from ‘true’ avoidable costs;
- the first PQ pair was then adjusted downwards to avoid the plant shutting down, as their contractual position with ESB Customer Supply does not allow them to recover start-up costs.

7.7. Tynagh entered into the Capacity and Differences Agreement (CADA) with ESB Customer Supply under terms agreed by the Commission for Energy Regulation. Under this agreement ESB Customer Supply bought the electricity produced by Tynagh and paid Tynagh its operating costs. However, the costs incurred in starting up the plant were not recoverable from ESB Customer Supply.

7.8. Tynagh considered that the CADA was in line with BCOP. The calculation of PQ pairs had been based on the opportunity cost to Tynagh as a result of the commercial impact of the CADA contract. The contract left them potentially exposed to financial loss in a number of areas. This, in their opinion, justified adjusting PQ pairs to account for the opportunity costs they face as a result of the operation of the contract.

7.9. Tynagh noted that the CADA Contract had already been re-negotiated for the SEM. If the operation of the contract was not in compliance with the rules of SEM, they would be willing to re-negotiate the contract if necessary.

7.10. **Airtricity** argued that, if contract costs were allowed as the basis for the calculation of commercial offer data, participants could effectively contract with themselves to bid in any way they liked. Allowing the market to bend to good or bad contract prices may have unintended consequences which would be likely to reduce social welfare. There were also questions on why Synergen's contract was not renegotiated with the implementation of the SEM.

7.11. **NIE Energy's PPB** had difficulty seeing how Synergen's bids based on contract gas prices fitted in with the general bidding principles. In the first instance, they questioned whether this was consistent with the direction given by NIAUR to PPB immediately prior to 1st November 2007, in relation to how the generation contracted to PPB under their long term power purchase agreements should be bid (i.e., using actual rather than contract rates for various technical and commercial parameters).

7.12. In terms of the specific issue of the relevant fuel price to use in the derivation of commercial offers, PPB did not argue that contract costs should never be taken into account. They believed, however, that in normal circumstances generators should be bidding commercial offer data based on the spot price of gas. Exceptions to this general rule should be limited, degressive, clearly defined and understood and time-bound within a transition period to ensure a consistency in approach.

7.13. One such exception to the general rule might be where legacy contracts could not be renegotiated. However, PPB did not accept that the Synergen situation met these criteria, not least because the residual term of the contract means the market distortion would not degress in the short or medium term, and furthermore, the remaining term should facilitate renegotiation of the contract at a low net cost in comparison to the overall contract value over the period.

7.14. **PPL** argued that new contracts should be treated in the same way as pre-existing contracts - both were potential distortions to the optimal scheduling of generation. There must be consistency in approach to provide a level playing field for those who did not benefit from legacy contracts.

7.15. **VPE** argued that bids based on contract prices reduced the transparency of the market. Contracts should be renegotiated to allow for SEM changes. Synergen should have taken all reasonable endeavours to do this and exhaust all alternatives. The necessary standard of proof was high.

8. The SEM Committee's Duties

8.1. The primary focus of the SEM Committee when reviewing the alleged Licence breaches was based on a plain reading of the applicable Licences and codes. As these documents must interact with other aspects of SEM, notably the Trading and Settlement Code, the SEM Committee formed its opinion in relation to the appropriate interpretation in accordance with its statutory duties, under which the Licences and codes were implemented and which it is required to advance in carrying out its functions.

Statutory Duties

8.2. The duties of the SEM Committee, the Commission for Energy Regulation and the Northern Ireland Authority for Utility Regulation are set out in Section 9BC of the Electricity Regulation Act (as amended by the Electricity Regulation (Amendment) (Single Electricity Market) Act 2007) in Ireland and in the Electricity (Single Wholesale Market) (Northern Ireland) Order 2007 in Northern Ireland.

8.3. The relevant duties (which are repeated in both provisions) are as follows:

(i) Principal duty

8.4. The principal duty of the SEM Committee is to *protect the interests of consumers* of electricity wherever appropriate *by promoting effective competition* between persons engaged in, or in commercial activities connected with, the sale or purchase of electricity through the SEM.

(ii) Other duties

8.5. In carrying out its principal duty, the SEM must have regard to:

- the need to secure that *all reasonable demands for electricity* are met;

- the need to secure that *authorised persons are able to finance* the activities which are the subject of obligations imposed by relevant law in Ireland and Northern Ireland;

- the need to secure that the functions of the Department, the Authority, the Irish Minister and Commission for Energy Regulation in relation to the SEM are exercised in a co-ordinated manner;

- the need to ensure *transparent pricing* in the SEM;

- the need to avoid unfair discrimination between consumers in Northern Ireland and consumers in Ireland.

8.6. Subject to the above, the SEM Committee shall carry out its duties in the manner best calculated to:

- *promote efficiency and economy* on the part of authorised persons;

- secure a diverse, viable and environmentally sustainable, long-term energy supply in Northern Ireland and Ireland; and

- promote research into, and the development and use of—

    - new techniques by or on behalf of authorised persons;

    - methods of increasing efficiency in the use and generation of electricity.

<u>Principles of good regulation</u>

8.7. The SEM Committee must also have regard to the common principles of good regulation set out by Governments in both the Republic of Ireland and in the UK. These principles – of proportionality, accountability, consistency, transparency and effectiveness (i.e., targeting) were adopted by the UK's Better Regulation Task Force, which was set up by the UK Government in September 1997 to advise the Government on action to ensure that regulation and its enforcement accord with those five principles. The same five principles were established by the Irish Government in the White Paper "Regulating Better" in January 2004. The SEM Committee, as a committee of the Northern Ireland Authority for Utility Regulation and of the Commission for Energy Regulation under the relevant legislation, is obliged to abide by those principles in exercising its functions.

Bidding Code of Practice

8.8. The aims of the Bidding Code of Practice, as set out at Paragraph 4 of the BCOP, are to:

- facilitate the efficient operation of the SEM by ensuring that generators and NIE's Power Procurement Business cannot exercise market power in the generation of electricity on the island of Ireland; and

- ensure that, in combination with the Capacity Payment Mechanism, generators are appropriately compensated for making available their generation sets or units (as appropriate) and for generating electricity in the SEM.

8.9. These aims are fully consistent with the principal objective of the SEM Committee (to protect the interests of consumers) and its various secondary objectives.

9. The costs associated with repeated starts

9.1. This section looks at the costs of repeated starts, whether those costs can legitimately be reflected in generators' commercial offer data and, if so, where they should be reflected – whether in start up costs, no load costs or in PQ pairs.

9.2. The original complaint was made about the bidding behaviour of Coolkeeragh and the analysis in this section refers explicitly to the costs Coolkeeragh claim are incurred if the plant is regularly two-shifted. However the principles are valid for all generators who are concerned to reflect the anticipated running regime of their plant in their commercial offer data.

<u>The costs of repeated starts</u>

9.3. The costs incurred when Coolkeeragh makes repeated starts reflect:

i. the costs associated with being contractually required to take the plant offline for a period of five days after a relatively small number of starts to inspect the compressor blades;

ii. the costs of replacing the compressor blades in the event that that a new set is required; and

iii. the increased risk of a repeat compressor failure.

9.4. These costs can be categorised as:

i. the O&M costs of regular inspections;

ii. the costs of a replacement set of compressor blades in the event that they are required;

iii. the loss of revenue from capacity payments and SMP while the plant is offline for inspection; and

iv. the costs associated with the risk of a repeat compressor.

<u>Are these legitimate costs?</u>

9.5. In considering which of these various costs could be reflected in a generator's bids under the Licence and the BCOP, the SEM Committee examined the wording of the Licence and BCOP in relation to this matter and noted in particular paragraph 3 of the Licence. This expressly requires the generator when calculating Short Run Marginal Cost to deduct the ownership, operation and maintenance costs of not operating and also states that this deduction can be a positive or negative figure.

9.6. Further, the BCOP establishes at paragraph 8 (iii) that "reasonable provision for increased risks to plant and equipment as a result of the operation of a generation set or unit" could be included in calculating the opportunity cost. In a consultation paper published in 2006 (AIP/SEM/73/06) the Regulatory Authorities anticipated that these provisions would be calculated by reference to the expected value of generator damage as a result of the running regime of the generator unit, using probabilities of a catastrophic event occurring by reference to experience, capped by premiums payable on catastrophic damage insurance policies, appropriately averaged over the coverage period. It was explicitly noted at the time that these calculations should relate to extraordinary efforts only. The routine operation of a generator unit introduces some risk of plant damage. But it was anticipated that this cost would be best considered as part of the normal annual O&M costs of a unit and not as incremental.

9.7. The SEM Committee considers that the BCOP and Licence conditions require that bids are cost-reflective. Bids should therefore take account of all avoidable costs incurred by a participant, taking account both of the costs of running and the costs of not running. The SEM Committee does not consider that a generator should be required under its Licence to incur significant avoidable costs without the prospect of being able to recover them, always excepting the sunk costs of past investment decisions. All avoidable costs should be capable of being recovered through some element of the participant generator's commercial offer data, including the prospective loss of capacity payments and infra-marginal rent from SMP as a result of an increased number and duration of outages that can be explicitly linked to the running regime of the plant.

9.8. Accordingly, the SEM Committee considers that all the avoidable costs outlined above – the additional O&M expenditure, the additional equipment costs, the increased risk of failure to plant and equipment as a result of the plant's running regime and the concomitant loss of revenue from capacity payments and infra-marginal rents from SMP - are allowable costs.

9.9. To do otherwise could threaten the development of efficient new entry and effective competition, given that it may dissuade generators from entering the market if they perceive that they may incur irrecoverable forward-looking costs when doing so. Operation within the market must be economically viable for competition to flourish. The SEM Committee considers that this can only be achieved by ensuring that all avoidable costs are recoverable.

How should these allowable costs be reflected in commercial offer data?

9.10. The Trading and Settlement Code (TSC) requires commercial offer data to be in a specific form:

- one no load cost;
- one to three start up costs, depending on the state of the unit at start (i.e., cold, warm or hot states); and

- between one and ten PQ pairs, which reflect the incremental cost of moving from one output level to another.

9.11. The SEM Committee considered that there are three possibilities:

i. The costs arise from starting repeatedly and should be reflected as a start up cost;

ii. The costs do not vary with the level of output of the plant and should therefore be included in no load costs; or

iii. The costs are related to the level of output of the plant and should therefore be reflected in PQ pairs.

9.12. While the SEM Committee does not wish either the cost reflective bidding Licence condition or the BCOP to become the vehicle for detailed rules on how costs should be allocated and valued, it recognises the need to provide clear guidance on the validity of including costs of two-shifting in PQ pairs.

9.13. In its initial draft report circulated to interested parties in February, the SEM Committee were of the opinion that the real, but difficult to estimate, risks and opportunity costs associated with repeated starts should be reflected in (reduced) PQ pairs. The SEM Committee thought that this would allow the generator the latitude to incorporate risks associated with operation in its commercial offer data, by adjusting its PQ pair bids downwards to see whether it could avoid two-shifting at an acceptable cost.

9.14. On further reflection and given the input of interested parties, the SEM Committee is now persuaded that the costs of repeated starts are invariant to either the hours of operation or the level of output of a generator. In a complex bidding system such as is in place in the SEM, the costs of repeated starts should not therefore be associated with either hours of operation or the level of output (i.e., either no load costs or PQ pairs). On this basis the most appropriate place to include a fixed cost of this nature, as the result of the number of starts the unit makes, is as an element of start-up costs. This is in accordance with the design of the SEM, where complex bids have been adopted and where participants might be expected to include in the start-up costs all the costs that are related to start-ups.

9.15. In reaching this decision, the SEM Committee was persuaded by the arguments put forward by interested parties that, while its initial decision was sound, allowing the costs of repeated starts to be reflected in reduced PQ pairs:

- would conflict with the design of the SEM, the aim of which is to ensure efficient centralised dispatch and has provided for the declaration of any start-up costs in the complex bidding structure;
- would risk facilitating predatory pricing;
- would reduce transparency in price formation; and
- could deter new entry by distorting the economics of inflexible plant.

<u>Are Coolkeeragh's estimates of the costs associated with repeated starts reasonable?</u>

9.16. The SEM Committee examined the detailed calculations provided by Coolkeeragh. These set out how the cost elements associated with two-shifting as indicated earlier in this section had been calculated. The explanations provided for the individual elements were well reasoned, and, in the opinion of the SEM Committee, reflected a fair estimate of the potential costs of repeated starts which would be incurred by Coolkeeragh.

9.17. Apportioning such costs across PQ pairs submitted in commercial offer data is problematic, as was pointed out by several participants during the course of this inquiry. The SEM Committee accepts that the commercial offer data submitted by Coolkeeragh reflected a reasonable effort to represent its SRMC accurately in its commercial offer data, taking account of costs it would face as a result of two-shifting. Nonetheless, for the reasons set out above, the SEM Committee considers that a proper understanding of the obligations contained in Coolkeeragh's cost-reflective Licence condition requires such costs to be included in the bids submitted by Coolkeeragh as an element of start-up costs.

10. The bidding of contract costs

Synergen

10.1. Synergen's start-up and no load costs and PQ pair bids since the SEM began in November 2007 have reflected the price Synergen pays for gas under its gas supply agreement (GSA) with its gas supplier. Under this agreement:

- gas is supplied to Synergen's Dublin Bay plant to meet the latter's electricity generation requirement but Synergen does not have title to the gas unless it is burnt for the purposes of electricity generation;
- the price Synergen pays for gas - once used for the generation of electricity in Dublin Bay - under the GSA is unrelated to the market price of gas; and
- there is provision in the GSA for the sharing of the gains to be made where the parties mutually agree that it would be mutually beneficial to sell the gas into the gas market rather than use it for electricity generation at Dublin Bay; but the gas supplier is not contractually obliged to agree to sell the gas in these circumstances.

10.2. The BCOP explicitly requires:

- that cost items are to be valued at their opportunity cost, which is defined as the value of the benefit foregone by the generator in using that cost item rather than in its most valuable realisable alternative use; and
- that in calculating the benefit foregone, where there exists a recognised and accessible market in that particular cost item, the value should reflect the market price of the cost item, unless it can be demonstrated that there is 'good cause' not to apply that principle.

10.3. The BCOP does not specify what constitutes good cause. The SEM Committee sees the good cause justification related to the contracted position of a generator as involving the application of a number of tests. These are:

- where a generator has unambiguous title to a cost item, including rights to dispose of the title as it sees fit and without encumbrance, prevailing market prices are the appropriate measure for calculating opportunity cost. This is because, where a party has full title to a cost item, the option exists to sell the cost item on the market, which, subject to the transactions costs involved, sets a lower bound on the value of the alternative uses of the cost item. Where the alternative use of the cost item is higher than the market price, then the cost item could be purchased on the open market instead; and

- where the right to dispose of a cost item which a generator is entitled to use in the generation of electricity is encumbered, good cause not to reflect prevailing market prices may exist.

10.4. In deciding whether good cause exists, the SEM Committee reviewed all its statutory obligations (as set out in Section 8 above) and identified the following as being particularly relevant to this issue:

- the protection of the interests of consumers by promoting effective competition, which in this context revolves around whether allowing the generator to calculate opportunity cost by reference to prices other than prevailing market prices would facilitate the exercise of market power; and

- securing that authorised persons are able to finance their activities, which means that, where a generator does not have title to an asset, or where the disposal of that asset is encumbered, it must be able to demonstrate that such impediments to its disposal could not reasonably be removed or could only be removed at disproportionate cost to the generator.

10.5. The SEM Committee is satisfied that Synergen's GSA was negotiated in good faith by two willing counterparties in a manner that was intended to share the risks and rewards for the conversion of gas into electricity at Dublin Bay.

10.6. The SEM Committee has examined Synergen's GSA. It is satisfied that, while Synergen is entitled to use gas for the generation of electricity under the terms of the GSA, it is not entitled to dispose of that gas to a third party. Where gas is not burned at Dublin Bay (e.g., because the plant is out of merit or is on an outage), the gas supplier retains ownership of the gas and is free to dispose of it in the manner most commercially beneficial to it.

10.7. There is no provision in the GSA that allows for automatic renegotiation of the contract where there is a defined change in circumstances. Any renegotiation would be at the discretion of both parties. The SEM Committee is persuaded that the encumbrances Synergen faces in the uses to which it can put the gas could only be removed at disproportionate cost.

10.8. The SEM Committee is persuaded, on its reading of the GSA, that the benefit foregone by Synergen in using the gas available to it for the purposes of electricity generation at Dublin Bay under the GSA is unrelated to the prevailing market price of gas. The benefit foregone by Synergen for using the gas for the purposes of electricity generation is the price it must pay for the gas, which is the contract price of the gas.

10.9. The SEM Committee is also persuaded that Synergen would be commercially disadvantaged were it directed to base its commercial offer data on the market price of gas. While Dublin Bay is unlikely to be the marginal plant over the next two or three years, the entry of newer CCGTs and the addition of more interconnection and wind in the medium term will eventually mean that Synergen is no longer in merit, other things being equal. At that point Synergen would suffer commercially as a direct result of being required to bid the prevailing market price of gas.

10.10. The SEM Committee does not consider that allowing Synergen *consistently* to reflect the costs it incurs under its gas supply agreement in procuring gas to generate electricity would facilitate the exercise of market power, over reward Synergen for making capacity available or otherwise undermine the achievement of the SEM Committee's primary or subsidiary objectives.

10.11. In coming to this view, the SEM Committee is mindful that the negotiation of Synergen's gas supply agreement pre-dates the All Island Project and the design of the SEM. In the interests of fairness, the SEM Committee would not expect such a contract to be renegotiated to the detriment of Synergen, given that Synergen may reasonably consider that their pre-existing rights and interests would not be encroached upon by the SEM. The SEM Committee is of the opinion that the SEM was not introduced to work against the legitimate commercial interests of its participants - except insofar as to mitigate market power - and the SEM Committee does not expect participants to give up pre-existing commercial advantages, so long as such advantages are not used to abuse a dominant position, which in this case they are not.

10.12. The SEM Committee is consequently of the opinion that Synergen has demonstrated good cause to calculate opportunity cost by reference to the price paid under the terms of its gas supply agreement.

<u>Tynagh</u>

10.13. In their submissions, Tynagh indicated that:

- all PQ pairs are first constructed from true avoidable costs.

- their first PQ pair is then adjusted to avoid plant shut-down, as their contractual position prevents them from recovering start-up costs.

10.14. Tynagh's contractual position is related to the price which it receives for electricity which it generates, rather than any input cost. However, it is arguable that the treatment of start-up costs under the CADA contract is equivalent to an encumbrance on the cost items associated with start-up/reducing production below minimum generation.

10.15. Nonetheless, the SEM Committee is of the opinion that, even if this approach were adopted, removing any impediments associated with the CADA contract is possible and would not impose unreasonable cost on Tynagh.

10.16. Aspects of existing contracts not compatible with either the rules of the SEM, or the rationale underlying it, could have been removed in contracts that were designed to apply in the SEM. The SEM Committee considers that the clauses in the CADA contract which allowed renegotiation on market reform could be used to remove aspects not compatible with either the rules of the SEM, or the rationale underlying SEM.

10.17. It is the SEM Committee's understanding that the CADA agreement was renegotiated before the start of the SEM to reflect the arrangements in the SEM. It should be possible to adjust the contract further to allow Tynagh to recover its start up costs.

<u>Cases other than Synergen and Tynagh</u>

10.18. The SEM Committee has accepted that in the particular circumstances of Synergen, there exists good cause to calculate opportunity costs based on the prices paid under its GSA. Where other participants are of the view that they are in a similar position to Synergen or that they have any other grounds to claim good cause under the BCOP, then they should contact the SEM Committee to request authorisation in advance of adjusting their bids.

11. Start-Up Costs of Moneypoint and Poolbeg

11.1. PPL's complaint related to the divergence between the start-up costs submitted by ESB PG for its Poolbeg and Moneypoint units, and PPL's estimates based on its understanding of the plants' technical characteristics. PPL made the following particular points:

- Poolbeg's costs did not reflect the information released as part of KEMA's data validation exercise undertaken on behalf of the Regulatory Authorities in early 2007. PPL also argued that their plant at Ballylumford is a "sister" plant to Poolbeg and does not incur comparably high costs.

- Moneypoint's start up costs were ten times those of Kilroot, a similar power plant, whereas the start up energy requirement ratios (as indicated by the KEMA data validation exercise) differed by no more than six times. AES Kilroot, in their submissions to this inquiry, also argued that the start-up costs for Moneypoint appeared unduly high compared those incurred at their coal-fired units at Kilroot.

11.2. The SEM Committee asked ESB PG to provide a reasoned explanation of how it had calculated its commercial offer data for these two plants. The SEM Committee examined the explanations provided; and retained specialist engineering consultants to assist them in assessing whether the data were in compliance with ESB PG's Licence obligations.

11.3. ESB PG's obligations under its Licence are only to include cost items associated with ownership, operation and maintenance of a generation set or unit in its calculation of short run marginal cost, and to value such items at their opportunity cost.

11.4. Under the cost reflective bidding Licence condition, the role of the SEM Committee is not to specify what items, or in what quantities, should be used in generating electricity. However, it must be satisfied that cost items included in calculating short run marginal cost are actually associated with ownership, operation and maintenance of a generation set or unit and that participants' commercial offer data reflect the opportunity cost of items actually used.

<u>Moneypoint</u>

11.5. ESB PG provided detailed workings of how they built up their commercial offer data, including their start-up costs – which are outlined at Annex 2. ESB PG maintained that the divergence between PPL's estimates of Moneypoint's start up costs and its submitted commercial offer data was largely the result of the fuel mix used to start Moneypoint (i.e. the use of gasoil and/or heavy fuel oil in starting).

11.6. The SEM Committee is satisfied that the various Moneypoint units were historically operated in a manner which would lead to opportunity costs associated with start-up in line with the commercial offer data submitted by ESB PG. Insofar as these costs are related to actual costs incurred during start-up, ESB's bids are in compliance with the cost reflective bidding principle.

11.7. However, the SEM Committee shares the concerns expressed by PPL relating to the very high start-up costs of Moneypoint units. The SEM Committee will review the actual operating costs of Moneypoint units on an ongoing basis; and retain specialist engineering consultants to assist in such inquiries.

<u>Poolbeg</u>

11.8. ESB PG's explanation for Poolbeg's start-up costs as submitted in its commercial offer data were that it estimated energy consumed for hot, warm and cold starts at 11,685 GJ. This is significantly higher than the energy used starting the similar plant at Ballylumford; and higher than the estimates produced for the early 2007 KEMA validation exercise of 3,000 GJ, 2,500 GJ and 2,000 GJ for hot, warm and cold starts respectively.

11.9. ESB PG's justification for this divergence was that the GJ allowance used in calculating commercial offer data was based on actual start data dating back to November and December 2001. The energy allowance was determined as follows:

- the energy (in GJ) required to synchronise the gas turbines (GTs);
- the incremental energy (in GJ) used but not recovered through no load or PQ pairs because, owing to Environmental Protection Agency (EPA) licensing, the GTs are required to dispatch quickly to a high load level to run in low NO_x mode;
- this results in the GTs running for a prolonged period over the inefficient open cycle mode;
- when steam conditions are right, steam can be brought to the steam turbine with half the plant transferring to the more efficient combined cycle mode.

11.10. The SEM Committee accepts that historically, and since 1st November 2007, Poolbeg has operated in the manner described by ESB PG; and that this mode of operation was chosen to ensure compliance with the EPA's environmental regulations.

11.11. The SEM Committee expects that ESB PG will keep under review how it meets its EPA Licence obligations in relation to Poolbeg to ensure that it minimises costs associated with compliance. The SEM Committee reserves its rights under Condition 18 of the Interim Electricity Generation Licence granted to ESB to specify a date by which ESB PG, shall, in consultation with the Commission for Energy Regulation, set out in writing how it proposes to comply with its obligations under applicable environmental laws.

11.12. The SEM Committee also accepts that the submissions in relation to heat rates during start-up are an accurate estimate of the costs incurred by Poolbeg from a cold start-up. The SEM Committee is of the opinion that although operation in the mode described by ESB PG may not result in substantial cost differences for warm and cold starts, any such differences should be fully and accurately calculated.

11.13. The SEM Committee has therefore asked ESB PG to produce accurate estimates of the energy consumed during warm and hot starts for Poolbeg and base its commercial offer data upon these estimates.

12. Summary and Decisions

12.1. Subsequent to the start of the SEM on 1st November 2007, complaints were submitted to the Regulatory Authorities by Viridian Power & Energy and Premier Power Limited regarding the commercial offer data submitted by several market participants. These complaints alleged that the commercial offer data submitted for several plants were not in compliance with Licence obligations on generators in relation to cost-reflective bidding.

12.2. The SEM Committee examined these complaints in accordance with published procedures and concluded that the issues raised merited a proper inquiry by the SEM Committee. The SEM Committee engaged extensively with participants in the course of its inquiry. This involved the consideration of a large amount of data and technical information from market participants, as well as undertaking a technical and legal review of the commercial offer data which prompted the complaints and hearing oral representations from all those affected.

12.3. The complaints raised three major issues arising from the cost-reflective bidding Licence condition and the Bidding Code of Practice (BCOP) established under it. These are:

- the appropriate treatment of the costs associated with repeated starts in a two-shifting running regime;
- what constitutes "good cause" under the BCOP to calculate opportunity cost based on contract terms and prices rather than prevailing market prices; and
- the accuracy of technical and engineering parameters underlying the calculation of start-up and no load costs for several ESB PG units.

12.4. Where the consideration of the complaints involved the exercise of judgment or interpretation on the part of the SEM Committee, this was done in the light of the Committee's statutory duties and objectives.

12.5. While it is not the desire of the SEM Committee to create detailed rules on how costs should be allocated and valued, it is accepted that there is a need to provide clear guidance on the appropriate interpretation of the various Licence obligations and codes binding on market participants.

View of the SEM Committee

Costs of repeated cycling

12.6. The SEM Committee considers that the direct and indirect costs attributable to the ownership, operation and maintenance of a generator unit are dependent on the running regime to which the unit is subject; and in particular on whether it is regularly cycled or two-shifted. Thus it is appropriate to account for the opportunity costs of repeated starts in the commercial offer data submitted to the market and system operators.

12.7. The SEM Committee also considers that the revenues foregone as a result of the particular running regime of a generator unit are an allowable cost item.

12.8. The SEM Committee considers that the costs associated with repeated starts do not vary with either hours of operation or the actual output of a generator unit, but are incurred as a result of the actual starts undertaken by a generation unit. The most appropriate place within a complex bidding system to include such costs, which are the direct result of the number of starts the unit makes, is as an element of start-up costs, as provided for in the Trading and Settlement Code.

Complaint in respect of the commercial offer data submitted for Coolkeeragh

12.9. The SEM Committee accepts that Coolkeeragh incurs high opportunity costs as a result of repeated starting. These opportunity costs have hitherto been reflected in a deduction from its minimum generation price. This treatment of such costs is, in the opinion of the SEM Committee, not in accordance with the proper interpretation of the cost reflective bidding Licence condition. As set out in paragraph 12.8 above, the SEM Committee considers that they should be reflected in start-up costs.

Good cause for using contract costs to calculate opportunity cost

12.10. The Bidding Code of Practice does not specify what constitutes good cause to calculate opportunity cost other than by reference to prevailing market prices. Consequently the SEM Committee must base its judgments on its statutory obligations. The considerations in relation to valuing cost items by reference to contractual prices which the SEM Committee see following from these obligations are:

- title to the cost item in question, or any contractual encumbrances on the free disposal of the cost item;

- the cost to the generator of removing any encumbrances or securing full title to the cost item; and

- the impact on consumers and the potential to facilitate the exercise of market power.

Complaints about COD submitted by Synergen

12.11. Synergen based its bids for Dublin Bay on its contracted cost of gas, not the market price of gas. The SEM Committee accepts that Synergen cannot freely dispose of gas procured under its Gas Supply Agreement. The SEM Committee is satisfied that removing such encumbrances would only be possible at disproportionate cost. Finally the SEM Committee is satisfied that allowing Dublin Bay to bid on the basis of its contractual gas costs would not have an adverse impact on the interests of consumers.

Complaints about COD submitted by Tynagh

12.12. Tynagh indicated that its commercial offer data were based on true avoidable costs, except that their initial minimum generation price was discounted to avoid the plant being shut down. Tynagh cannot recover start-up costs under their off-take contract with ESB Customer Supply. Discounting their initial minimum generation price was intended to ensure that the plant was not shut down, thus avoiding costs which would not be reimbursed under the contract.

12.13. .Tynagh's contract was renegotiated in preparation for the SEM under clauses allowing renegotiation on market reform. The SEM Committee considers that such clauses could be used to make the contract compatible with the rules of the SEM, and the rationale underlying the SEM. While no formal estimation of costs has been made, it is envisaged that such renegotiation could take place without imposing undue costs on Tynagh.

Complaints about ESB PG Generation

12.14. The SEM Committee accepts that historically and since 1st November 2007 Poolbeg has operated in the mode described by ESB PG, and this operational mode was chosen to ensure compliance with environmental regulations.

12.15. The SEM Committee accepts that the ESB PG's submissions in relation to heat rates during start-up are an accurate estimate of the costs which are incurred by Poolbeg in starting up from cold. Commercial offer data based upon these data (appropriately valuing the fuel consumed) are cost reflective.

12.16. The SEM Committee is of the opinion that, although operation in the mode described by ESB PG may not result in substantial cost differences for warm and cold starts, these should be more accurately calculated. These estimates should be used as the basis for commercial offer data submitted for Poolbeg.

12.17. The SEM Committee is satisfied that the various Moneypoint units were historically operated in a manner which would incur opportunity costs associated with start-up in line with the commercial offer data submitted by ESB PG. Nonetheless the SEM Committee is concerned by the high costs associated with operation of Moneypoint and will monitor the operation of Moneypoint units on a continuing basis.