Commission for Energy Regulation Industry Forum

Choices for Irish Electricity Trading Arrangements

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Executive Summary

The CER is undertaking a review of the electricity trading arrangements, as required in The Policy Direction (Trading in Electricity) issued by the Minister for Public Enterprise to the CER in 27th July 1999. This review will result in a set of electricity trading arrangements which will apply to a fully opened electricity market. The high level principles of the future market will be decided early in 2003.

This review was accelerated in order to provide early and clear information about the future of the electricity market.

The objectives of this review are consistent with CER's duties and functions as set out in Section 9 of the Electricity Regulation Act, 1999. In this regard a number of different areas need to be taken into consideration in this review and these include:

- security of supply;
- promotion of competition;
- minimising transaction costs for participants and customers;
- fostering renewables; and
- demand side management.

This paper represents the beginning of the consultation process for the wholesale market review. CER are keen that stakeholders are involved in the consultation process.

This paper provides a high level view of the types of options available and how they may be tailored to the particular circumstances of the Irish market. It is deliberately non prescriptive and is intended to elicit a wide range of views.

This paper provides three options for trading arrangements (status quo, decentralised market and centralised market). The paper also discusses two important institutional and structural issues (generation adequacy and market dominance) and options to resolve these issues.

The CER would invite comments and ideas on this paper by 16th December. During this period CER and PA will be available for bilateral discussions with interested parties. CER will also be considering these options during this period and developing evaluation criteria.

During the week commencing 10th February 2003, CER will publish a more detailed paper having taken into account all comment received. Following consultation on this paper, CER will produce a subsequent paper indicating the proposed way forward in the week commencing 17th March 2003. The CER may consider scheduling a further industry workshop at this point if participants feel this would be useful.

The CER would invite comments and ideas on these issues. These should be submitted to Clíona McNally, preferably in electronic format, by **16th December**. During this period CER and PA will be available for bilateral discussions with interested parties. CER will also be considering these options during this period and developing evaluation criteria.

For further information and to submit comments or arrange meeting please contact:
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1. INTRODUCTION

1.1 BACKGROUND

The Policy Direction (*Trading in Electricity*) issued by the Minister for Public Enterprise to the CER on 27 July 1999 sets out in broad terms the electricity trading arrangements, which would apply to the independent sector for a transitional period between 19 February 2000 and 19 February 2005. The trading arrangements that have been in place since 19 February 2000, as embodied in the Trading and Settlement Code, reflect the broad principles of that Direction.

Among other things, the Policy Direction required that:

> "The Commission for Electricity Regulation will carry out a review of the overall trading arrangements early in 2004, with a view to introducing, after completion of the transitional period, appropriate wholesale market arrangement[s] applying equally to all bulk electricity generation and supply in Ireland."

CER decided, after consultation with interested parties, that the trading arrangements review required by the Direction should begin in 2002 and that the high level principles of the future market should be decided by early in 2003. This review of the trading arrangements was accelerated because:

- experience suggests that putting in place new electricity trading arrangements takes a considerable length of time to fully implement; and
- it is important, from a regulatory perspective, to give existing and potential participants in the sector as much advance warning of critical future changes to the terms on which they will trade after 19 February 2005. Given the long lead time between planning and executing projects, particularly in generation, potential new entrants need to know now what the future arrangements will look like if they are to be successful in putting together financial arrangements for those projects.

1.2 OBJECTIVE OF REVIEW

Given its statutory duties under the Electricity Regulation Act, 1999, CER needs to consider what trading arrangements will best meet its objectives. CER proposes that the following is an over-riding (or primary) objective:

- the trading arrangements should deliver an efficient level of sustainable prices to all customers, for a supply that is reliable and secure in both the short and long-run.

This primary objective of the CER is consistent with its duties and functions as set out in Section 9 of the Electricity Regulation Act, 1999. In this regard a number of different areas need to be taken into consideration in this review and these include:

- security of supply;
- promotion of competition;
- minimising transaction costs for participants and customers;
- fostering renewables; and

- demand side management.

Over the next few months CER will develop these and other objectives for the trading review to provide an evaluation framework for assessing the suitability of any proposed new arrangements. These criteria will be presented as part of the public consultation process in February 2003.

1.3 SCOPE OF REVIEW

In designing arrangements to replace the transitional trading arrangements, it is appropriate to focus on the wholesale market comprising trading between all generators and all suppliers in Ireland. It is envisaged that in doing so the review will cover a wide range of issues. The scope of the review shall include consideration of the following:

- details of alternative trading arrangements – for example, whether to opt for a gross pool (through which all energy is bought and sold, subject to *de minimis* limits) or a net pool (in which only imbalances are traded out);
- whether a financial market(s) should be developed, e.g. spot, futures and forwards, and what financial products should be available or whether the market should be left to develop these products themselves;[1]
- how many markets there should be. Candidates include markets for energy, capacity, ancillary services, reactive power and frequency response;
- how many prices there should be in the gross/net pool, and how prices should be set (i.e., at the system marginal price or pay as bid, or by the intersection of demand and supply bids); and
- whether, and if so how, the demand side should be explicitly included in the trading arrangements.

The special circumstances of the Irish market would lead to special consideration being given to the issue of security of supply. The review should therefore consider:

- whether there should be separate payments to generators for making capacity available, to enhance security of supply (as is the case now in Ireland for dispatchable generators which are available but not dispatched), or whether payments for energy alone are sufficient; and
- whether a party is responsible for the introduction of additional capacity to the market (if required).

The review must also take into account the network issues that may impact on the trading arrangements:

- how losses should be treated;
- what access rights should parties have to the transmission and/or distribution networks;
- how transmission constraints should be dealt with and how the costs of resolving constraints should be recovered; and

[1] This will be subject to financial regulation where appropriate.

- whether generators should be allowed to self commit (i.e., decide when to synchronise with the system and when to reach a specified level of output); or self despatch; or whether the system should continue to be subject to central despatch.

It will also be important in considering these design issues to have regard to the market structure which is likely to be in place post 2005. Thus the following issues need to be considered:

- the present and prospective extent of competition in generation and supply;
- the impact of market power held by different parties in the generation and supply markets; and
- the arrangements for ESB's supply franchise in 2005 including provision for last resort supplier and regulation of retail tariffs.

CER has a duty to promote renewables and combined heat and power (CHP). The existing interim arrangements have fostered the development of these sectors. CER will consider:

- the impact of any proposed arrangements on renewable, sustainable or alternate and CHP sectors.

At present the Irish market operates in relative isolation but this may not continue into the future. The arrangements that will be put in place must be viewed in a wider competitive arena. Issues for consideration include:

- the capacity and impact of the existing interconnectors with Northern Ireland and with Scotland through Northern Ireland and the scope for interconnection directly with Wales;
- the development, use and impact (if any) of interconnectors between the Irish and England and Wales markets;
- the trading arrangements in Northern Ireland and proposals, as they develop, for complementary all Island markets in electricity and/or gas;
- the increasing interactions between electricity and gas; and
- EU developments (e.g. arrangements relating to cross border energy flows).

CER will also need to have regard to the governance arrangements which will need to be put in place for 2005. The process of migration from the existing arrangements to the permanent solution is an integral part of the implementation phase and how this is best achieved will be addressed by CER. The CER is also concerned that the arrangements put in place for 2005 will respond flexibly to changing circumstances in the future. In deciding the most appropriate arrangement CER will wish to draw on the accumulated experience of designing and running markets in electricity in a number of countries round the world and experience to date in Ireland.

1.4 PROCESS AND TIMETABLE

This paper represents the beginning of the consultation process for the wholesale market review. CER is keen that stakeholders are fully involved in the consultation process and this section sets out the process that will be followed.

This paper is designed to be a high level view of the types of options available and how they may be tailored to the particular circumstances of the Irish market. It is deliberately non prescriptive and is intended to elicit a wide range of views. **The CER would appreciate comments and ideas on these issues by 16th December.** Between now and then the CER and PA will be available for bilateral discussions with interested parties. CER will also be considering these options during this period and developing an outline evaluation.

During the week commencing 10 February 2003 CER will return with a more detailed paper. This will be presented at a second industry forum. This paper is unlikely to reach a firm conclusion but is intended to demonstrate the current thinking within CER and the issues that remain unresolved at that stage. The programme provides for a subsequent consultation period in which participants may give their views on this paper.

Following this consultation phase, CER will produce a paper indicating the proposed way forward although some issues may remain outstanding in the week commencing 17th March 2003. Depending on the issues involved and the extent of consensus from participants to the direction being proposed, a further industry workshop may be considered at this stage of the process.

2. *TRADING ARRANGEMENTS*

These following chapters present a high-level description of the options for trading arrangements being considered by CER. Each option, as presented, has been simplified to distil it to its essential features. In practice, trading arrangements for individual countries draw from different “pure” models to accommodate the particular issues about the industry structure, market size, physical system, commercial imperatives and the political and legal requirements of the country. Seldom, if ever, can a market structure be lifted from one geography and applied directly to another.

In order to facilitate the discussion of trading arrangements, the paper has purposefully left until later a number of important issues. These issues are either common to all trading arrangements or depend on the choice of the trading arrangement selected.

Also, there are two major institutional and structural issues that transcend trading arrangements and overlay any selection of trading arrangements. These issues, generation adequacy and ESB dominance, are discussed in Chapter 3.

2.1.1 Trading Arrangement options

There are two basic paradigms that overarch electricity industries and trading arrangements:

- a regulated industry with activity (which may include trading between entities) driven primarily by regulated utilities with closely regulated tariffs is the traditional structure from which almost all current industries have emerged. It grew often from a government (or local government) owned and controlled sector. As electricity came to be seen as an essential social and commercial commodity this control assured the development of the required infrastructure and aimed to achieve the equitable provision of supply to all consumers. While a highly regulated industry has served countries well it suffers from much of the inefficiency and lack of commercial incentives common to all regulated industries. The advent of suitable technology both in the provision and distribution of electricity and in the organisation of alternative trading structures has led to the traditional regulated model being challenged as the most suitable paradigm for the future.
- a deregulated industry with trading driven by competitive forces, where competing participants set prices and quantities according to their individual commercial advantage. Because of the existence of monopoly and oligopoly elements in the industry it may be necessary to have some regulation even in a deregulated industry.

CER considers that any move from the status quo must be towards a more deregulated market.

Three basic trading arrangement options are presented for consideration:

- the Status Quo option is included since it is the default outcome for this review if no better alternative is found, as discussed in chapter 3;
- a decentralised market (sometimes called a “net pool”) as presented in Chapter 4; and
- a centralised market (or a so-called “gross pool”) as discussed in Chapter 5.

2.1.2 Key concerns

We note several key concerns that help shape the final options:

- the industry structure provides the context for market operations. The current structure features a dominant generation company and a dominant retailer, although new entry has occurred.
- it is essential that the market be consistent with encouraging new investment into the industry. Currently the market is close to absorbing its reserve capacity at peak times. New generation from private investors has been slow to commit to enter the Irish market.
- it should be cognisant that bilateral contracts may exist when the trading arrangements take effect.
- it should assist the management of transmission congestion and improve transmission planning as well as providing equal access to the grid for all existing and new generators. System congestion and difficulty of access for plant are problems. Plans are in place for expansion of the grid but with rapid economic growth having taken place one might anticipate that the demand will continue to grow with resultant on-going congestion.
- the trading arrangements should help with the provision and management of stringent operating reserve requirements. Large plant and a small system traditionally create a problem obtaining and scheduling reserve without also limiting economic dispatch of energy.
- pricing rules should provide for uniform retail prices across the country.
- the market should be designed to discourage the abuse of dominant positions and limit undue price volatility. The combination of two of the situations facing Ireland, a dominant generator and tight reserve capacity, would normally be expected to create high wholesale prices and price volatility.
- the trading arrangements should not hinder interconnection to other grids as appropriate and should not prevent the convergence towards a future all-island market.
- the basic market should be flexible enough to provide an open transition path to any further industry restructuring at a later date. Although further restructuring is not planned a good market design should lay a foundation suitable for both the immediate needs of Ireland and reasonable possible future industry scenarios without the need for a major design overhaul.

3. *STATUS QUO*

The status quo option is an extension of the current transition trading arrangements by making them permanent. This option is a form of regulated industry but with some aspects of competition through bilateral contracting and offering into the imbalance markets. As an on-going solution the status quo would require that, as far as the structure will permit, any weaknesses of the existing regulations would be eliminated or mitigated.

The option as described here incorporates anticipated changes due to come into effect 19 February 2005.

3.1.1 Governance

The industry is regulated by CER, under the Electricity Regulation Act, 1999, and various Statutory Instruments. The market rules are determined by the CER. The Trading and Settlement Modification Panel is an industry group through which modifications to the Code are proposed and discussed for submission to the CER.

3.1.2 Regulation

There is a comprehensive regime of regulation of utility generation, some imbalance prices and retail prices.

3.1.3 Industry structure

A. MARKET OPERATOR ("MO")/SYSTEM OPERATOR ("SO")

There is an independent transmission operator (ESBNG), which also handles the current balancing settlement.[2]

B. BUYERS AND RETAILERS

ESB PES is a dominant buyer of wholesale energy. PES sells on regulated tariffs to non-eligible and eligible retail customers who have not changed supplier. There are several retailers including Energia, BGE Supply, Duke, and ESBIE, a ring-fenced company owned by ESB, who serve eligible customers. Airtricity and CH Power, examples of Green and CHP suppliers, respectively are permitted to sell to any customer.

C. GENERATORS

There is one dominant generator ESB PG that holds over 85% of the generation capacity (not including its 70% ownership of Synergen's 400MW). PG is vertically integrated with PES. The remaining capacity consists of independent generation plants that are, in some instances, vertically integrated with retailers.

D. TRANSMISSION AND DISTRIBUTION

The transmission and distribution networks are owned by ESB and maintained by ESB Networks, which is a ring-fenced division of ESB.

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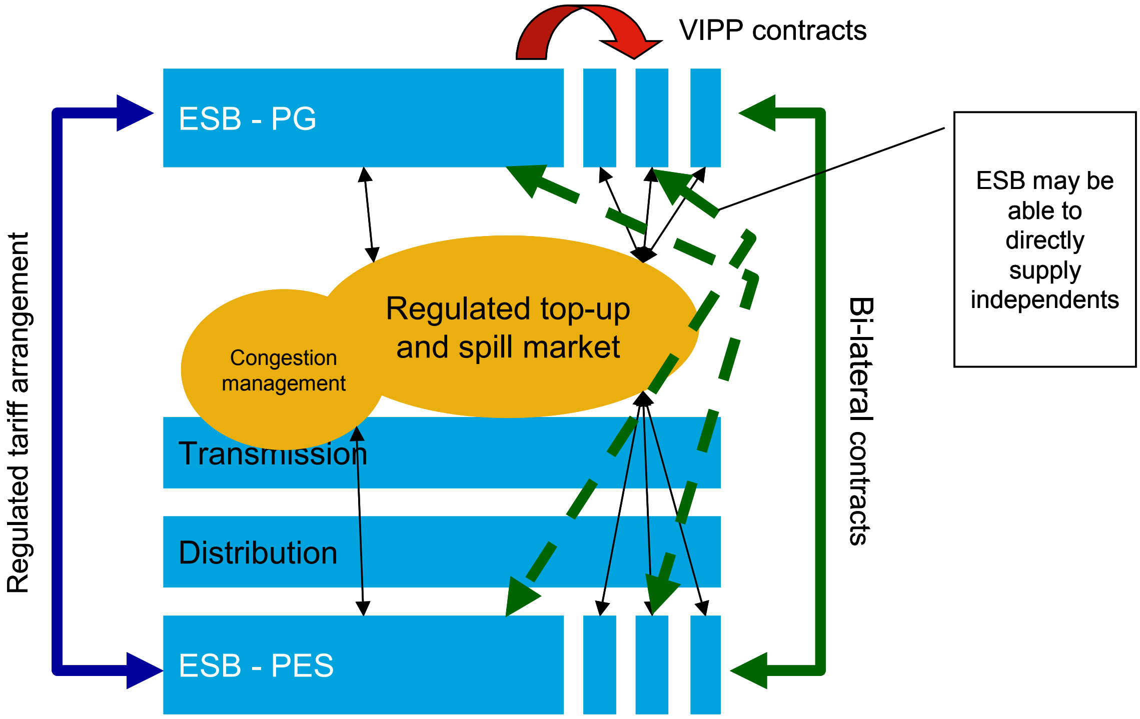
[2] ESB National Grid (ESBNG) is the current Transmission System Operator license holder and is set to become Eirgrid.

Figure 1 Industry relationships in the status quo



3.1.4 System Operation and Dispatch

ESBNG operates the system based on bilateral contracts between generators and retailers. These contracts are dispatched according to their contractual rights through ex-ante nominations (self dispatch within demand constraints) and access rights.

There is a regulated imbalance mechanism ("top-up" and "spill") operated by the ESBNG to settle imbalances or differences between participants nominated contractual positions and their actual ex-post production or consumption.

ESBNG, acting as SO, resolves system infeasibility and congestion by constraining plant on and off.

3.1.5 Energy Markets

The majority of energy traded is not subject to market forces rather it is settled according to bilateral contracts and internal sales arrangements between ESB PG and ESB PES.

Spill and top-up energy trading for load imbalances is through an imbalance market. The top up price is a regulated tariff set ex-ante by the CER. The spill price is set ex-post by the highest decremental bid of a generator that can be turned down in the half hour period in question. ESB PG acts as market maker as it is mandated to buy or sell according to market needs. [3]

System feasibility requirements are purchased as required by the SO.

[3] The format of the imbalance market is set down in the Minister's Policy Direction in Trading of July 1999.

3.1.6 Ancillary services

The Grid Code requires that dispatchable generators be capable of supplying the ancillary services of operating reserve and reactive power. They provide these services under dispatch instructions. Currently there is a regulated schedule for providing payments for these arrangements and ESBNG is in the process of putting contracts to cover these services in place. For new black start going forward there will be a competitive tender. Interruptible load, a type of operating reserve supplied by demand customers, is paid for under a regulated rate, which customers can apply for.

The cost of ancillary service provision is recovered through the Transmission Use of System (TUoS) tariff.

3.1.7 Price setting

Energy prices are set by the terms of bilateral contracts between non-ESB parties and by the CER in the case of ESB PG and ESB PES.

The financial imbalances are settled by separate top-up and spill prices.

Plants dispatched away from their ex-ante nominations, that is, their desired dispatch, for the purposes of resolving system infeasibility/transmission constraints are paid on the basis of their incremental bid when they are increased and pay their decremental bid when dispatched down.

Retail tariffs are either regulated by CER, for all consumers who are with ESB PES, or negotiated with independent retailers for all other customers.

3.1.8 Settlement

Settlement of bilateral contracts is by the parties to the contract.

Energy imbalances are settled by ESBNG and the parties are invoiced.

3.1.9 Capacity Assurance

A. GENERATION CAPACITY

Currently the spill price contains an additional capacity element which is paid under certain conditions and which is capped.

B. TRANSMISSION CAPACITY

Transmission expansion is planned by ESBNG, constructed by ESB Networks and authorised by CER.

3.1.10 Green, renewable and indigenous energy sources

From 1 January 2003 peat generation will be supported by a public service obligation (PSO), which will be paid by all electricity retail customers via their electricity bill.

Renewable, sustainable or alternate plant is licensed as a green energy producer.

Any consumer is eligible to purchase green energy from a retailer with a green energy supply licence or CHP energy from a retailer with a CHP supply licence.

3.1.11 Retail Competition

Retail competition exists for eligible customers. Retail competition in the Green or CHP sector exists for all customers irrespective of eligibility or consumption level.

ESB PES services all customers who do not move supplier, or choose to return to PES, under tariffs regulated by the CER.

3.1.12 Transmission Access

There is regulated third party access to the transmission grid. Currently access is addressed under the CER direction and decision regarding Firm and Non Firm Access to the Transmission System.

This option is the first of two that describe trading arrangements based on a competitive market. It is a decentralised or "net pool" trading arrangement that is a natural extension of many other market arrangements, where buyers and sellers make bilateral decisions without reference to a central agency. In order to accommodate the special requirements of an electricity system, there is a mechanism whereby the imbalances between proposed trades and actual supply and demand, as well as system feasibility, are handled centrally.

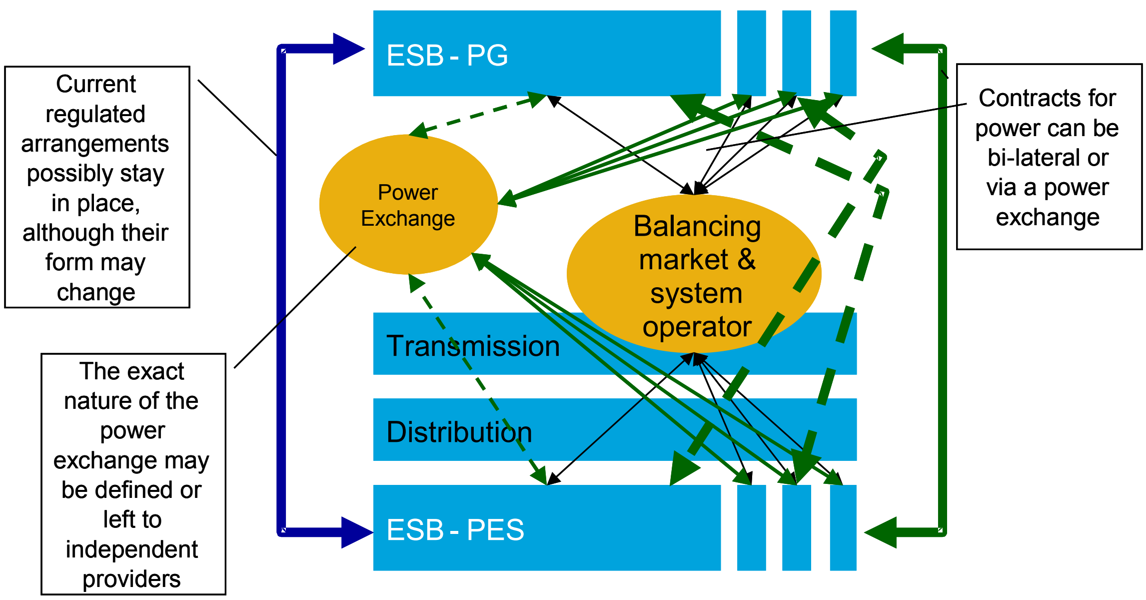
A fully decentralised market is based upon bilateral contracts with a balancing mechanism to handle trade and system-constrained imbalances. The market design is predicated on all parties estimating closely their real time load requirements and covering them with bilateral contracts.

It is decentralised in that parties holding contracts specify them for dispatch without reference to each other. The SO co-ordinates them by buying increments and decrements to ensure the power system is feasible. Only in the extreme circumstance of system infeasibility can the SO default a specified bilateral contract.

Some forms of the design seek to penalise activity in the imbalance market. In that case an active and liquid contracts market for bilateral contracts of various terms and quantities is required for the parties to limit their exposure to the imbalance market.

The version of the decentralised market presented here is consistent with the current industry structure in Ireland while commenting on areas where a change in structure would improve the trading arrangement.

Figure 2 Industry Relationships in the Decentralised Market



4.1.1 Governance

Governance of the balancing and settlement organisations is by the regulator or an industry board.

4.1.2 Regulation

In a competitive market the role of the regulator is usually considerably reduced. Regulation of the market will tend toward monitoring market power issues.

- Initially regulation involves developing and approving the industry structure and trading arrangements.
- Operationally regulation would tend to focus on ensuring efficiency in the transmission and distribution businesses.
- The regulator is likely to have an increased role in ongoing market surveillance and investigation of instances of monitoring and exploration of market power abuses.

For the future Irish market trading arrangements, although ESB PG will not have monopoly sales rights to ESB PES, there may still need to be regulation of the contractual relationship between ESB PG and ESB PES.

4.1.3 Industry structure

A. MO/SO

The independent SO and a balancing market operator (BMO) may be same entity but are usually separate from all the operators of other markets (e.g., power exchanges for the trading of bilateral contracts).

B. BUYERS AND RETAILERS

To work effectively the basic market design requires many buyers and sellers with no one having the ability to influence the markets and a strong incentive to actively trade in bilateral contracts. The design does not work well with a single dominant buyer. Hence, industry disaggregation would facilitate better working of this type of market. Also, since the primary market activity is the negotiation of bilateral contracts, it is essential to have commercial entities in the market.

C. GENERATORS

To work effectively the basic market design requires many sellers with no one buyer having the ability to influence the markets. The design does not work well with a dominant generator because that party will have market dominance as buyer of the bilateral contracts. Again, industry disaggregation and the presence of commercial entities would facilitate better working of this type of market.

Generators and retailers may be vertically integrated or not, although integrated companies may need stricter regulation.

D. TRANSMISSION AND DISTRIBUTION

Transmission and distribution operations would remain regulated as a natural monopoly provider.

Preferably, transmission asset owners should be separate from energy buyers and sellers. The transmission company who owns the transmission grid should also be separated from the SO to ensure the removal of conflict (ie, preferential access or dispatch of the system/market to the benefit of affiliate market participants) in the dispatch over the grid.

To promote retail competition distribution asset owners should be separated from retailers in order to ensure open and unfettered access over the distribution network.

In practice, little variation is expected from the current ownership.

4.1.4 System Operation and Dispatch

Contractual commitments or schedules are declared to the MO/SO which uses these commitments as the basis for dispatch. Where possible all contracts are dispatched as specified.

The differences between contract quantities and actual quantities are settled through a net dispatch imbalance mechanism controlled by an imbalance market.

The SO is responsible for ensuring system feasibility around the bilateral contracts and can use the imbalance mechanism to achieve this.

All generators are responsible for ensuring their units are “committed” for dispatch when requested by the SO in response to their bilateral contract positions or offers into the imbalance market.

4.1.5 Energy Markets

Buyers and sellers primarily conduct energy trading through a range of contracts. Since a key objective of this market mechanism is managing around balanced supply and demand submissions to the SO, contracts need to vary from long and medium-term contracts to very short-term contracts. As retailers’ demand, and generators’ supply, may change or be unpredictable in the very short term, it is necessary for them to trade contracts on a regular basis and at short notice.

To facilitate the requisite liquidity, trading markets (power exchanges) should exist to trade bilateral contracts, especially short-term contracts. The MO does not normally run these power exchanges. Markets dependent upon liquid contracts are finding that sufficient depth in trading is emerging slowly. This is likely to be a particular issue for small markets.

Imbalances between contracted quantities and actual dispatch and off-take are bought by the MO/SO as increments or decrements of energy in the imbalance market(s). If insufficient increments and decrements are offered to the MO/SO it has power to take compulsory action on participants at a regulated imbalance price.

4.1.6 Ancillary services

Ancillary services can be self-provided by those who submit schedules to the MO. If they are not self-provided the MO procures the services and charges the cost to schedulers who have not self-provided.

4.1.7 Price setting

All bilateral transactions are settled at their contracted prices.

The imbalance market may be (but need not be) split into separate buy and sell markets. Split markets are used to encourage accurate contracting quantities and to discourage the use of the imbalance mechanism. The imbalance markets may use a system market-clearing price or be "paid-as-bid".

Transmission and distribution charges are regulated tariffs

Where full retail competition exists retailers set retail prices.

4.1.8 Settlement

Settlement can be complex in this option. Financial settlement is between bilateral parties and with the MO, based upon physical settlement data from the SO/MO. Many parties will need to gather data and maintain the ability to settle contracts. While this may push the cost and difficulty away from the central market operator, this cost and difficulty is pushed out to market participants.

4.1.9 Capacity Assurance

A. GENERATION CAPACITY

There is no direct control of capacity additions in this market, with the market delivering new capacity when the expected market price is high enough to cover the long run marginal cost of new entry plant. Price signals to encourage investment are provided through the energy prices revealed in bilateral contracts. This price discovery is usually through power exchange trading that develops with published forward prices for several months in advance.

B. TRANSMISSION CAPACITY

No radical change is anticipated in approach from that under the Status Quo.

4.1.10 Green, renewable and indigenous energy sources

The market mechanism does not in itself provide special incentives to CHP generation. Incentives for such generation could be addressed outside the trading regime.

However in practice, generation with uncontrolled dispatch such as wind may be disadvantaged depending on the details of the imbalance market.

4.1.11 Retail Competition

This option is consistent with full retail competition in that it fits well with contracting between many buyers and many sellers.

4.1.12 Transmission Access

The design of this market is predicated on open access to the transmission grid. Open access means that parties have equal access to the transmission grid. Transmission access in practice is a function of two factors:

- the declared bilateral contract schedule; and
- system feasibility.

When the declared bilateral contract schedule causes congestion, use of the network is determined by the system operator through its acceptance of bids/offers for dispatch variation in the imbalances market.

5. CENTRALISED (INTEGRATED) MARKET OPTION

The centralised market design has been developed from the integration of the economic theory of operating an auction market and the physics and engineering of operating a power system. This combination produces a methodology that is simultaneously consistent with both. In most instances the theory is coded into a "market-clearing engine" – the dispatch software – that determines both the dispatch quantities and the market prices.

The industry structure and institutions are designed around this market operation to ensure that it works with as little market distortion as possible.

Since the market is cleared in a way that creates optimal dispatch instructions, all energy to be physically dispatched is required to pass through the market.

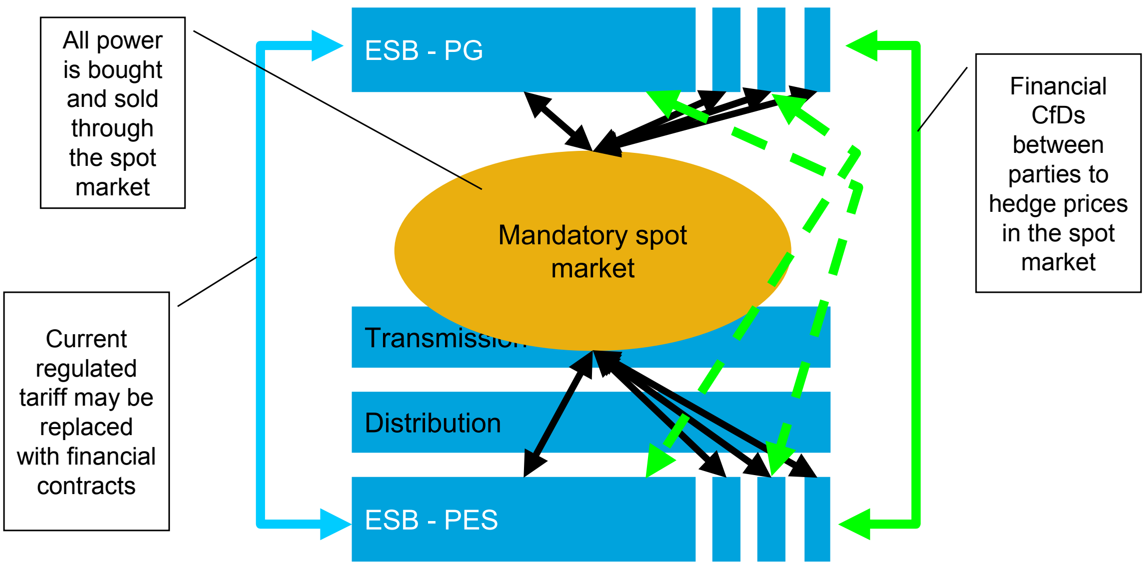
The structure creates coordinated auctions for real-time energy trading (the spot market), day-ahead energy trading, as well as trading of reserves and regulation.

In addition to the short-term auction markets there are contracts for energy that enable participants to ensure their revenue and mitigate their exposure to the spot market in the same way that traders in other industries (e.g., foreign exchange) hedge their exposure.

Inherently, the spot market auction process is particularly volatile because of the nature of electricity system that has an obligation (subject to specified standards) to instantaneously supply all demand in real time without recourse to inventory. High prices are expected when the supply-demand gap becomes tight. Market prices above a plant's variable cost act as a reward for its fixed costs and return on equity and so are a necessary aspect of the market.

It is expected that a centralised market will include a spot market, but that a thriving contract market will exist around that spot market. As market participants hedge their exposure to the spot market, they will enter into hedge contracts, with these hedge contracts forming the basis for the broader contract market.

Figure3 Industry relationships in a centralised market



5.1.1 Governance

Industry governance is by the regulator or representative industry board.

5.1.2 Regulation

Regulation will not be significantly different in principle from that present in the decentralised market.

With the spot market taking a greater role, the regulator will need to monitor market power in that market. In Ireland, with a single generator having the potential to exercise significant market power the regulator would need to ensure structures and monitoring programmes are in place to ensure this market power is not abused.

5.1.3 Industry structure

A. MO/SO

This form of market has an independent system operator (SO) and market operator (MO). They may be the same entity but are not part of any other industry participant or in any way trade in the market.

B. BUYERS AND RETAILERS

There can be any number of buyers. Retailers, large consumers and traders can be registered buyers from the spot market provided their load can be distinguished by the MO for settlement. Unlike the decentralised market this type of market might operate with a supply company. However, having few buyers may hinder the contract markets that will co-exist with a spot market.

C. GENERATORS

The market design will work for any number of generators greater than one. However, to work effectively it requires many sellers with no one having the ability to unduly influence the markets. Hence, like the decentralised market, this market will work better if the industry is disaggregated.

Generators and retailers may be vertically integrated or not, although dominant integrated companies may need some form of regulation to control their ability to exercise market power.

D. TRANSMISSION AND DISTRIBUTION

There are no significant differences under this regime from that under the decentralised market.

5.1.4 System Operation and Dispatch

The power system is centrally dispatched at the commencement of each dispatch period by determining dispatch instructions for each generator and dispatchable load. The dispatch of energy and allocation of reserve capacity is determined by the SO/MO based on offers made by generators and bids made by buyers. The dispatch process is centred on the spot market for energy so that dispatch is fully coordinated with a spot market.

A centralised dispatch market can permit either self-commitment or centralised unit commitment of plant.

Where central commitment is practiced the plant submits offers (or has as standing data) that include start-up costs, minimum running levels, minimum up-time and down-time, hydrology restrictions (for hydro) and other relevant plant data as well as energy offers - probably for every dispatch period for the day ahead. The SO optimally schedules plant start-ups and shut-downs to minimise the total cost of energy and unit commitment.

Alternatively, the generator can be responsible for managing its own start-up and shut-down and make “energy-only” bids into the market.

The SO uses ancillary services to deviate the power system from issued dispatch instructions during the dispatch period.

5.1.5 Energy markets

The spot market for energy is likely to consist of only a real time market that usually involves compulsory participation by all dispatchable generators.

Alternatively, there may be a voluntary firm day-ahead market together with a real-time imbalance market. The firm day-ahead market is a substitute for very short-term contracting practiced in a decentralised market.

There are usually indicative (pre-dispatch) markets run several times prior to the actual real-time market. These are for the disclosure of anticipated dispatch and prices so that participants can re-align their bids to achieve their desired dispatch outcome.

5.1.6 Ancillary services

The centralised market structure facilitates the central coordination of the provision of load following reserve and operating reserves with energy. Ancillary services can be offered into the spot market along with energy.

When reserves are offered with energy they are “co-optimised” with the energy offers to achieve an overall system minimum cost solution for energy and reserves.[4] This ensures the most economic reserve capacity is selected.

Interruptible load can be offered to the market as a (relatively cheap) source of operating reserve and in so doing release more expensive (in opportunity cost terms) generating capacity for energy supply.

5.1.7 Price setting

Both spot market prices and day-ahead market prices are usually based on a system marginal price. This price is usually determined from the highest cost generator offer or lowest buyer bid that must be accepted to clear the market. It could be set by regulation.

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[4] The ‘co-optimisation’ of reserve and energy means that offers for energy and reserve are accepted simultaneously on the basis of least total cost for all products. For example, a generator’s bid price for energy will influence whether they are accepted for reserve.

This price can be set either "ex ante" based on predicted load (and consistent with dispatch instructions) or "ex post", in the real time market, based on actual load (consistent with actual load off-take and dispatch).

The prices faced by participants may vary according to their location on the network. These are termed locational marginal prices (LMPs) or nodal prices. The prices have three components:

- a system marginal price,
- a loss component that prices the cost of losses,
- a congestion rental that prices the cost of congestion caused by transmission constraints or system security constraints.

The latter two price components are unique to the "node" at which the participant is connected in the network and reflect the losses and congestion it faces compared to a reference node.

Alternatively, the price may be set uniformly on a zonal or system-wide basis. Various methods are used including:

- using only the SMP and ignoring the loss and congestion components, or
- averaging the LMPs for all appropriate nodes in the zone.

When zonal or system-wide prices are used participants may need to be compensated for being dispatched "out-of-merit". This means their dispatch and the market price are inconsistent with their offer into the market (e.g., they have been dispatched even though their offer is above the market price).

5.1.8 Settlement

Settlement is in two stages.

- financial settlement with the MO/SO. Buyers settle against their purchases and sellers against their sales in the various markets (real time market and day-ahead market, if applicable).
- bilateral contracts are settled outside the spot market. These contracts will normally be hedge contracts although other types of bilateral contracts can be settled around this form of market.

Both settlement processes may be offered by the MO/SO so that participants may settle either their gross or net purchases from the spot market as they choose.

5.1.9 Capacity Assurance

A. GENERATION CAPACITY

Approaches similar to those discussed under the decentralised market are also appropriate here.

This form of market gives a very high level of price disclosure since spot prices, covering all energy, are published for every trading interval. Usually, hedge contract prices are commercially secret, but are expected to converge with average spot prices in the medium to long term.

B. TRANSMISSION CAPACITY

Transmission expansion and charging are outside the trading arrangements but will influence them. The methodology for the centralised market regime is similar to that for a decentralised market and Status Quo.

5.1.10 Green, renewable and indigenous energy sources

The market mechanism does not in itself provide special incentives to CHP generation. Incentives for such generation could be addressed outside the trading regime.

However, this market regime is comparatively "green-friendly" in that non-dispatchable plant such as wind and mini-hydro can be offered into the market to ensure they run when available and receive the spot market price. It is normal, but not essential, that such plant carry some of the cost of the SO acquiring load following capacity.

6. QUESTIONS ON TRADING ARRANGEMENT OPTIONS

CER would like your input on the preferred trading arrangement option:

1. Which of the three trading arrangement options are preferred?

2. Is there another trading arrangement option or variation that you feel should be considered? If so, what are they?

7. INSTITUTIONAL AND STRUCTURAL ISSUES

Institutional, legal, structural and other factors outside the electricity trading arrangements will have a significant impact on the working of the electricity market, regardless of the choice of trading arrangements

In Ireland, two major institutional and structural issues have the potential to significantly influence the market outcome of any trading arrangements selected. They are generation adequacy and ESB as a dominant market participant. The overall Irish electricity market may experience significant disruption and dislocation if measures are not in place to address these two issues.

Accordingly, CER presents alternatives to address these two issues.

7.1 GENERATION ADEQUACY AND CAPACITY MECHANISMS

7.1.1 Concern for Generation Adequacy

A reliable supply of electricity is assumed in most countries. As the electricity industry shifts to markets, there may be concern regarding the extent to which a market will deliver a level of reliability that is consistent with the public desire for a secure and reliable supply of electricity.

To address this concern, some have argued that electricity markets must include capacity mechanisms. Arguments for a capacity mechanism generally tend to be based around the following propositions:

- there are very long lead times required to bring on new infrastructure and high spot prices may not emerge far enough ahead of the requirement for new capacity to avert a shortage;
- spot prices that are subject to mitigation measures (eg some form of capping) may not provide sufficient signals even in a shortage situation; and
- the cost of investing to cover the event of a shortage is borne solely by the investor, whereas the benefits tend to accrue to all electricity users. The existence of this positive externality is likely to lead to under-investment in reserve capacity.

There is currently relatively little excess capacity in the Irish system, with the capacity shortfall expected to worsen as a result of load growth, planned peat plant retirements, and the slow pace of new entry.

The CER is in favour of introduction of an electricity market for Ireland that provides an adequate level of generation through market entry with no external intervention. However, there remains a concern the market may not deliver an acceptable level of generation adequacy.

In carrying out its duties under the Electricity Regulation Act 1999 the CER shall have regard to the need to promote the continuity, security and quality of supplies of electricity. The CER is currently engaged in a review of trading arrangements which will identify how new generation can be encouraged prior to the implementation of new trading arrangements in early 2005.

Also, CER presents here a set of alternatives that would help ensure an acceptable level of generation. The alternatives presented here would work in conjunction with the new trading arrangements and would be consistent with any near-term options undertaken by CER to alleviate capacity shortage in 2005.

7.1.2 Capacity Reserve Margin

Electricity system reliability is ultimately measured in physical outcomes. Avoidable involuntary load shedding (i.e. blackouts due to insufficient generation) would unnecessarily undermine consumer and investor confidence in the emerging market. The CER has made it clear that reliable electricity supply is, and will remain, a high priority issue as a matter of policy.

Electricity systems operate with uncertain and fluctuating levels of supply and demand. A central planner would design this system with sufficient generating resources to meet this demand for much of the time. [5] Regardless of the level of reliability selected (e.g., 1 hour of outage in 10 years), this approach means that there is more capacity installed in the system than the expected peak demand. This allows the system to maintain reliable service even when major components (e.g., power plants or transmission lines) are out of service on the peak hour of the year. The resulting excess capacity is referred to as the reserve margin, with reserve margin targets being set at various levels depending on the system.[6]

A large electricity system may have many power plants and a highly meshed transmission network, so that the outage of any single power plant or transmission line would mean only a small shortcoming in percentage terms. A smaller system might need a higher reserve margin due to the relatively larger impact on the system from the failure of a power plant or a transmission line. Each system will have a different target reserve margin that reflects the desired level of reliability and the details of the system.

7.1.3 Generation Adequacy in Deregulated Markets

In the traditional regulated industry model, the regulated utility would have an obligation to maintain a sufficient level of reserves, with the cost of doing this included in the overall bundled tariff to customers.

As the electricity industry is transformed and markets introduced, the integrated utility may no longer be integrated, may no longer have a monopoly, and may no longer have an obligation for (or incentive to supply) sufficient generation adequacy.

One of the promises of electricity markets is that new investment in generation plant (and perhaps in transmission infrastructure as well) will be determined by the market. The competitive market would determine the timing, size, location, fuel type, and other features of new generation plant with the result being a more efficient investment regime.

In electricity markets, the need for generation resources is signalled through market prices. Participation in the electricity market would give rise to investor expectations of

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[5] For the purposes of this discussion, interruptible demand that can substitute for generation should be considered a generation resource.

[6] The reserve margin can be specified either before or after allowing for operating reserves.

future net revenues (profits) associated with potential investments. If expected profits provide an appropriate risk-adjusted return, investments will be made.[7]

Several basic market design principles underlie a fully competitive electricity market, with these principles helping to ensure that market generation entry is forthcoming:

- all participants should expect that the structure of the market is fixed and that any changes are consistent with the stated market principles (regulatory certainty);
- the market should be allowed to operate without constraints (e.g., price caps) that would reduce or remove the profit potential for new entrants (i.e., no expectation of intervention);
- spot price volatility *per se* should not be regulated, even when electricity commodity markets produce extremely volatile outcomes;
- a contract market should be allowed and encouraged that will provide an efficient means to manage volatility of spot prices and to enable participants to hedge price risks by taking and supporting positions (and investments) based on their evaluation of future opportunities – perhaps supported by other risk instruments such as insurance products;
- market participants should be responsible for managing their own risks.[8]

The electricity market, if properly structured and working well, may provide sufficient capacity to obtain the desired level of reliability. There is, however, no guarantee that the market will equilibrate to a level of reliability desired by the regulator:

- while markets are expected to bring in new investment naturally, even without impediments to market entry, the risk-return calculation performed by the industry may result in a lower reliability level than the regulator desires. Such a level may depend on capturing price spikes from a higher proportion of outages than the regulator considers acceptable.[9]
- also, there is a grave risk that the market will not bring in new investment to an acceptable level during the initial years of the market, when market participants have an incomplete view of the Irish electricity market and have had insufficient experience upon which to base the significant investment required for a new power plant.

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[7] Absent any persistent barriers to entry. It must be noted that the development of a new large power plant or a new large transmission line is likely to present considerable hurdles related to siting, permitting, licensing, and other factors.

[8] Risk is an essential element of electricity markets. It is risk that either directly or indirectly provides the incentive for reserve capability and hence reliability of supply. If contract arrangements are hedges against the spot market price, one party or the other at some stage accepts the risk of being forced to buy from the spot market in order to meet the contract. The perceived level of risk will determine the level of response. Market intervention in the form of price caps, for example, might be something that market participants would seek from regulators or governments as a substitute for hedging in the contract market. If participants who buy in the electricity market feel that they will be protected from risk by intervention, they may decline to hedge risk by entering into contracts and reduce or remove incentives for new entry.

[9] Indeed in perfectly competitive market where all plant is bidding its short-run marginal cost there must be some significant expectation of outage to reward the top of the merit order peaking plant. In practice, this may be overcome by that plant having sufficient market power to bid above its SRMC in times of very tight supply and demand balance.

7.1.4 Safety Net for Capacity Assurance

Any additional mechanism to ensure generation adequacy will require an intervention in the working of an electricity market and should be purposefully structured as a "safety net" that will only be used in the event that the market does not produce an adequate level of generation. It could be argued that the existence of a mechanism to intervene in the market may have the unintended result of changing the incentives to and behaviour of market-driven entry[10].

Safety net mechanisms could play a constructive role during the maturation and transition phases of the development of a new electricity market in Ireland. Safety net features are important during the period in which the market is developing the precedents that will eventually be taken for granted by market participants. They provide greater assurance that an adequate level of supply reliability will be maintained during the period in which market participants and regulatory entities gear up to deal with the new operating realities and investment incentives of a commercial environment.

However, it could also be the case that in improving the level of reliability, a safety net mechanism, if invoked, will dampen the market signals for market-lead new entry by increasing competition and lowering prices.

Even if market mechanisms are intended as the primary means to achieve an acceptable level of reliability, it is a very different matter to completely abandon the concept of a safety net that deals directly with the physical elements of the market in all circumstances. Therefore, until it can be clearly demonstrated that market intervention measures are unnecessary and market entry will provide a reliable electricity system, a safety net may be a desirable feature of the Irish electricity market.

Safety nets nevertheless should only be safety nets. These mechanisms are in place to protect against a potential disaster, not to be the primary driver of new entry. The purpose of safety net mechanisms, therefore, should be well defined, and their time scale and scope of application should be clear and appropriately limited. To the extent possible, activation and operation of safety net mechanisms should be transparent and well understood by all market participants.

On the other hand, there is significant opinion in some countries that electricity markets should include some sort of capacity scheme. This is based on the belief that electricity markets alone may never achieve the level of reliability desired by the regulator. However, with the higher level of capacity installed in the market, the expected market price may be suppressed below the market's own trigger price required for sufficient new investment. This may result in the capacity mechanism becoming entrenched in the market for the long term.

A middle ground between total reliance on the market and a permanent capacity mechanism is that the capacity measure might be put in place with the clear intent to transition from a major market feature to a safety net to sole reliance on the market.

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[10] For example, if new investors are aware of incentives they may hold off their own initiatives in order to gain the incentive.

7.1.5 Capacity Mechanism Options

In carrying out its duties under the Electricity Regulation Act 1999 it is expected that, regardless of the details of the mechanism selected, CER would:

- decide on a target for reliability (e.g., a reserve margin measure);
- monitor the market to identify potential generation shortcomings early enough to address them;
- approve the decisions and activities of the entity that administers the capacity mechanism; and
- ensure that any costs incurred in procuring capacity are collected from an appropriate group of customers.

Some options to encourage new capacity are described below. Some of these options refer to a new entity termed the "Default Buyer" that is established to administer the capacity mechanism. The Default Buyer might be the same entity as the market operator or could be a new entity that is not engaged in other market activity. The Default Buyer would not be one of the existing market participants and would not become a market participant aside from the operation of the capacity mechanism.

Capacity options include:

- the Default Buyer could enter into hedge contracts (if a centralised market is selected) or bi-lateral contracts (if a decentralised market is selected) with a new entrant, acting as the counterparty to the contracts. The Default Buyer would then on-sell these hedge contracts or bi-lateral contracts to any takers in a non-discriminatory manner. The on-sell of these contracts might also be used to encourage competition in the supply business.
- the Default Buyer could hold tender processes that are aimed at providing a financial incentive that would induce sufficient new entry into the Irish market, with the incentive payment supplementing the new entrant's expected profits from participation in spot and contract markets. In this situation, the Default Buyer is not the counterparty to any energy contracts, but provides an incentive payment in return for a demonstrated commitment to build capacity on an agreed schedule.
- a requirement for generation adequacy could be placed on supply companies. In this option, each supply company licence would include a requirement that the supply company maintain ownership or control (i.e. through bi-lateral contracts or hedge contracts) an amount of generation capacity that exceeds its peak customer demand by a specified amount (e.g., 125% of customer peak demand). This option might include penalties for non-performance (fines or preferential outages when there is a shortage, as in the proposed Standard Market Design model) or might mean that a supply company without sufficient capacity would be forced to buy contracts at regulated prices (i.e., by the Default Buyer)[11].

[11] The Standard Market Design (SMD) has been approved by the FERC and is implemented in PJM.

7.1.6 Questions on potential capacity mechanisms

CER would like input on this option:

1. Is a capacity mechanism necessary in the Irish electricity market?

   CER would like to understand whether there is interest in establishing a capacity mechanism in the Irish electricity market. Please provide your comments on whether such a measure is necessary.

2. How prominent a role should such a measure play?

   Should the capacity mechanism be a prominent part of the market (e.g., a generation adequacy measure similar to that in the FERC SMD), or only a safety net that would only be triggered when there is serious potential for the market to fail to deliver desired levels of reliability?

3. Should a capacity measure be permanent?

   Should a capacity measure, however constituted, be something that is a permanent feature of the Irish electricity market or should the capacity mechanism be subject to planned obsolescence (i.e., triggered by the passage of time or by the amount of capacity reserve in place due to market entry).

7.2 DOMINANT PARTICIPANTS

7.2.1 Concern Over Market Dominance

ESB is a large presence in the Irish electricity market and the situation is likely to continue for some time after the market is fully opened. ESB PowerGen ("PG") holds a share of generating capacity that is estimated to be in excess of 70%. ESB PES is the supply company for all non-eligible customers and will continue to supply under a regulated tariff to those customers who do not choose an independent supplier. Transmission and distribution are business units within ESB. PG and PES are also a part of ESB and are currently within a single business unit.

ESB's dominance is a result of its Irish government's monopoly control over the electricity industry until recent years. While this dominance was an accepted part of the then utility regime, it may be cause difficulties within a liberated market.

There is evidence that dominant market participants have the potential to undermine the working of electricity markets. The concerns range from, on the one hand, the potential for a large participant to raise spot or contract market prices to a high level to, at the other extreme, the potential to produce market outcomes that will deter new entry (e.g., by "predatory pricing" – deliberately suppressing prices in order to discourage competitors, or by exercising market power in the markets for fuels.).

Additionally, the commonality of interest between PG and PES may mean that the benefits which derive from a liberated supplier market may not be realised.

New entrants may see the issue of ESB market dominance as adding risk to a new investment, even when the economic evaluation of an investment was otherwise favourable.

Accordingly, CER seeks to undertake measures that would remove much, if not all, of the potential difficulties from the reality of ESB market dominance.

Additionally, there are other issues of concern that may be resolved by the same mechanisms that are used to mitigate and control potential generator market power. The primary issue is the continued existence of the ESB supply company (PES) as the provider of regulated tariffs to customers not taking service from market supply companies. The inherent inertia of customers to change suppliers will result in PES remaining a dominant supplier for some years. In this environment, some careful thought must be given to the way in which new suppliers can develop in the market.

There is also a need to look at the energy trading arrangements between PG and PES, including the issue of dealing with volume mismatch, as customers leave or return to PES while PG's generating portfolio remains fixed or even diminishes due to retirements.

7.2.2 Market Power

Market power exists in the spot market where bidders have the ability to raise prices or withhold capacity in order to increase profits. In a perfectly competitive market, a bidder would be unsuccessful at increasing its payoff by either of these strategies through the normal functioning of the market – i.e., the lost profit from using the strategy would outweigh the additional profits from higher prices on the remaining production.

The most obvious place where market power might be exercised is in a spot market, but the potential for market power exercise is also present in bi-lateral contract markets and in hedge contract markets.

We explore several options, including contracts, price caps, and bid controls.

7.2.3 Contracts

A. CONTRACTING TO MITIGATE MARKET POWER

Imposed contracts have proved to be an effective mechanism for mitigating market power in electricity markets. These are usually imposed on the market by the regulator.

It has been shown that contracts have a beneficial impact on market power in spot markets because contracts tend to put downward pressure on spot prices if a generators' contract coverage is sufficiently high. Consequently a high level of contracting has been used to reduce the impact of market power in the spot market[12].

However, market power can also impact adversely on the contracts market:

- generators with market power have an incentive to sell fewer contracts than they would in a competitive market in order to retain their market power in the spot market; and
- contract prices (or premiums) will be above competitive levels as a result of prices above competitive levels, so that generators will achieve profits from market power in the contract market.

Generators with market power will only voluntarily enter into contracts if those contracts embody the above-competitive rents they could otherwise earn in the spot market. These contracts might subsequently make the spot market appear competitive, but would not eliminate the rents from market power.

Hence, contracts that are designed to mitigate the effects of market power will have to be based on prices that remove above-competitive rents. Contracts that can be shown to mitigate market power in the spot market will also mitigate market power in the related contract markets.

The effect of imposing a contract is to reduce or remove the profitability potential of raising prices/reducing output and losing marginal output. By fixing the price received for some proportion of output, the net profit from raising prices by bidding up a marginal unit (and losing output on that unit) is reduced.

In the context of a spot market, these contracts would take the form of contracts for differences (CfDs). A CfD is a financial hedging contract referenced against the spot market price. In a market with bilateral contracts, these contracts could be physical bilateral contracts with imposed prices and quantities. The effect on generator profits and payoffs is basically similar under both physical and financial contracts.

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[12] This has two effects. A high level of contracts reduces the “leverage” the spot price has on a generator’s revenues since only a small proportion of the load is subject to that price. Also, it increases the competitiveness of the spot market by increasing the proportion of uncontracted generation to uncontracted load.

CfDs are financial instruments in which one counterparty agrees to pay to the other the difference between the contract price (strike price) and the prevailing spot price. [13]

The two-way contract has the effect of fixing wholesale purchase costs (or revenues) for the contract quantity at the specified contract price, irrespective of the underlying spot price. The one-way contract caps[14] spot prices for the contract quantity at the contract strike price. Thus, two-way CfDs modify the revenue that generators earn from the spot by fixing or capping revenue on a portion of power sold. A generator that has all its output covered by contract has limited exposure to the spot market, and its revenues are then determined largely by the contract terms.

A generator that has no contracts is fully exposed to the spot market. Generators with market power are able to raise the spot price in order to raise their profits in the absence of contracts.

When fully contracted, any extra profits from gaming in the spot market would be paid out to counterparties under the terms of the CfDs. If a generator earns no additional profits from gaming in the spot market, then it has no incentives to indulge in such behaviour.

Thus, abuse of market power could be mitigated by contracting all (or most) of the output from generators using CfDs.

However, a heavy burden of two-way hedge contracts may have the perverse result of lower-than-competitive spot prices. A fully contracted generator generally has incentives to force spot prices down, for two reasons:

- deter new entry and improve their competitive position in the future; and
- minimise financial risk if they become over-contracted as a result of plant outages that leaves them exposed to buying from the market at the spot price.

Generally, there is some compromise level of contract cover below 100% that sufficiently reduces incentives for incumbent generators to abuse their market power but does not give them incentives to push down spot prices. Careful selection of these contracts will yield a spot price that proffers allocatively efficient prices, which reliably signals the market risk, and encourages efficient consumption and investment decisions.

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[13] For example, if the spot price is €30/MWh and the contract strike price is €20/MWh, the seller of the contract is then required to pay to the buyer of the contract €10/MWh, the difference between the two prices. There are two forms of contracts in common use in power markets based around spot markets:

- a two-way contract is usually defined solely in terms of a MWh quantity and a €/MWh strike price. For the defined quantity, the seller agrees to pay the difference between the contract price and the spot price to the seller. Thus, if the spot price is below the contract price, then the buyer pays difference payments to the seller but if the spot price is above the contract price, then the seller pays difference payments to the buyer; and
- a one-way cap contract is usually defined in terms of a MWh quantity, a €/MWh strike price and a fixed € payment or option fee. Under a one-way contract the seller of the contract agrees to pay difference payments to the buyer only if the spot price is above the contract price. If the spot price is below the contract price, then no difference payments are made. One-way floor contracts are also possible.

[14] One-way contracts can also be used as price “floors” to support generator revenue.

It should be noted that contracting as a mechanism for mitigating market power has the downside that it blunts this instrument as a means of hedging risk – which is its normal function.

B. CONTRACTING FOR TARIFF CONTROL

Contracts also provide a mechanism for transferring spot revenues earned by generators to final customers. In Ireland, such contracts might be put in place between PG and PES.[15] To the extent that contracts are imposed for the purpose of market power, care must be taken to minimize barriers to competition in both generation and retail supply and avoid hindering the development of retail competition.

The design of a set of contracts that would effectively mitigate market power, achieve PES tariffs that were reasonable, and avoid other unfavourable impacts on the market will require considerable care. The use of a portfolio of contracts, appropriate pricing mechanisms, and the selection of an appropriate counterparty will be required.

The Irish power market is highly concentrated and short of capacity. This may mean that such contracts have a fairly long term, with options to renew the contracts if the conditions remain.

C. CONTRACTING MECHANISMS

Several mechanisms are possible for imposed contracts:

- the easiest system to administer would be a direct contract between the incumbent generators and the incumbent retailers. This arrangement is tenable if and only if the average purchase costs under the contract are consistent with expected competitive wholesale prices; contract prices below competitive levels give the incumbent retailers an advantage in the competitive retail market, prices above these levels place them at a disadvantage.
- an alternative is to make individual customers the contract counter-parties, such that a customer retains the contract entitlement if they switch between competing retailers.
- another option is to impose a third party between PG and PES, with this paper referring to this entity as the "Dominant Buyer." As with the Default Buyer in the capacity mechanisms, this entity could be the market operator or another party. The Dominant Buyer might also be the Default Buyer. In any case, the Dominant Buyer would be a regulated entity that is not a market participant beyond its clearly defined role as the Dominant Buyer.

Imposed contracts for differences seek to mitigate market power by altering the incentives on generators to manipulate spot prices and quantities.

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[15] As discussed elsewhere, PG and PES are a single company. The implicit hedge arising from this vertical integration may have similar effects as an imposed set of hedge contracts, with the CER-administered PES tariff to end-use customers effectively setting the financial terms of this contract.

7.2.4 Price or bid caps

In some jurisdictions direct bid controls have been proposed for the control of market power[16]. These may effectively cap the bids that generators can submit at a pre-determined level, or limit the bids based on prevailing prices or previous bids.

These caps could apply uniformly to all bidders or could be tailored to fit each bidder. As the name suggests bid caps are simply imposed controls on bid levels. These are usually controls on maximum bids for a unit, but may also be constructed as floors where predatory pricing behaviour is a potential issue. Bid caps may be indexed against fuel prices to reduce price risk for generators.

In practice it is difficult to establish workable bid caps for peak and mid-merit plants. These plants will often set clearing prices, and the bid caps act to effectively limit peak and shoulder prices to the cap prices. This approach suffers from the level of quantity risk inherent in such plant. Spot prices must be high enough on average to return fixed costs to peak plant if generators are to make them available to the market, and generators should have an adequate opportunity to recover depreciation and return on capital. However, the load factors achievable for these units are subject to wide fluctuations, given variations in demand, new entry levels, etc. By capping prices, the generator may be at considerable risk that its peak units will never recover its going-forward costs. Since these peak hours are also a major contributor to total generator margin, setting these prices will effectively alter generator returns across the broad portfolio of plant as well. They may also distort the type of capacity that is installed.

To the extent possible it is advantageous to remove this level of regulatory risk from the market and rely on other mechanisms to control peak prices.

Some markets suggest a price screen mechanism where the price screen results in caps that are a function of time of day (e.g. on peak), increase above a reference price (e.g. trailing average price), or whether a unit runs frequently or infrequently out of merit. Price screen mechanisms may be more effective than straight bid caps.

However both straight bid caps and price screens effectively result in the regulation of peak and mid-merit plants and prices. If Ireland wishes to return to direct economic regulation, then there are much simpler and less expensive mechanisms than setting up a spot market with regulated prices or bids.

7.2.5 Questions on ESB Dominance

CER would like input on this option:

1. Is it necessary for CER to undertake to design and implement measures related to mitigating ESB PG market dominance?

2. Should CER also use any ESB PG market dominance mechanisms to control ESB PES tariffs?

3. What is the preferred mechanism for this?

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[16] We distinguish this use of market price cap from that of limiting price risk in immature markets. Price caps used for this purpose are somewhat higher and place a cap on the size of a price spike. However, many of the arguments outlined here also apply to such caps.

4. Should such mitigation measures be permanent?