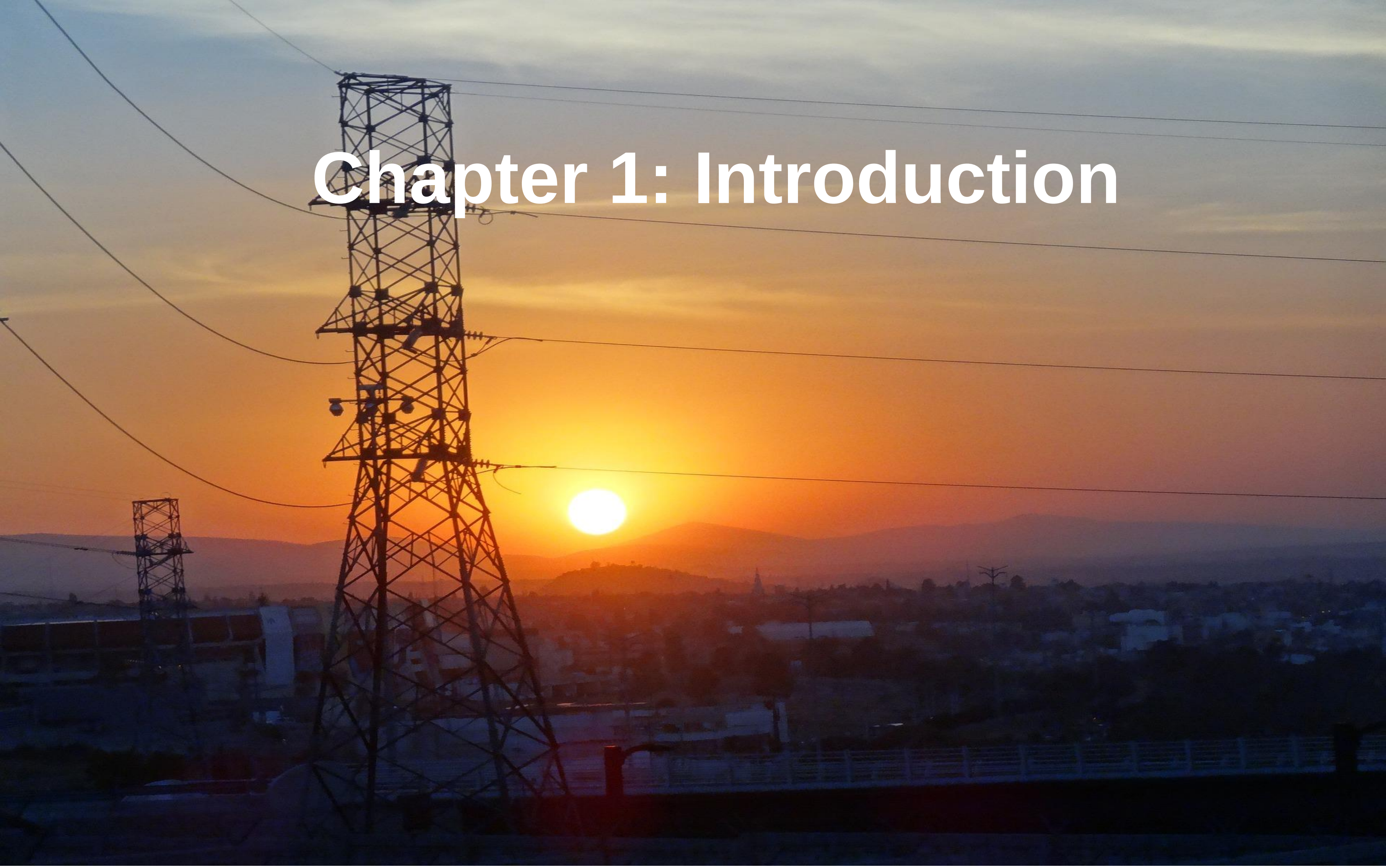
I-SEM Training
TSO Scheduling

September 2017

EIRGRID semo Single Electricity Market Operator SONI

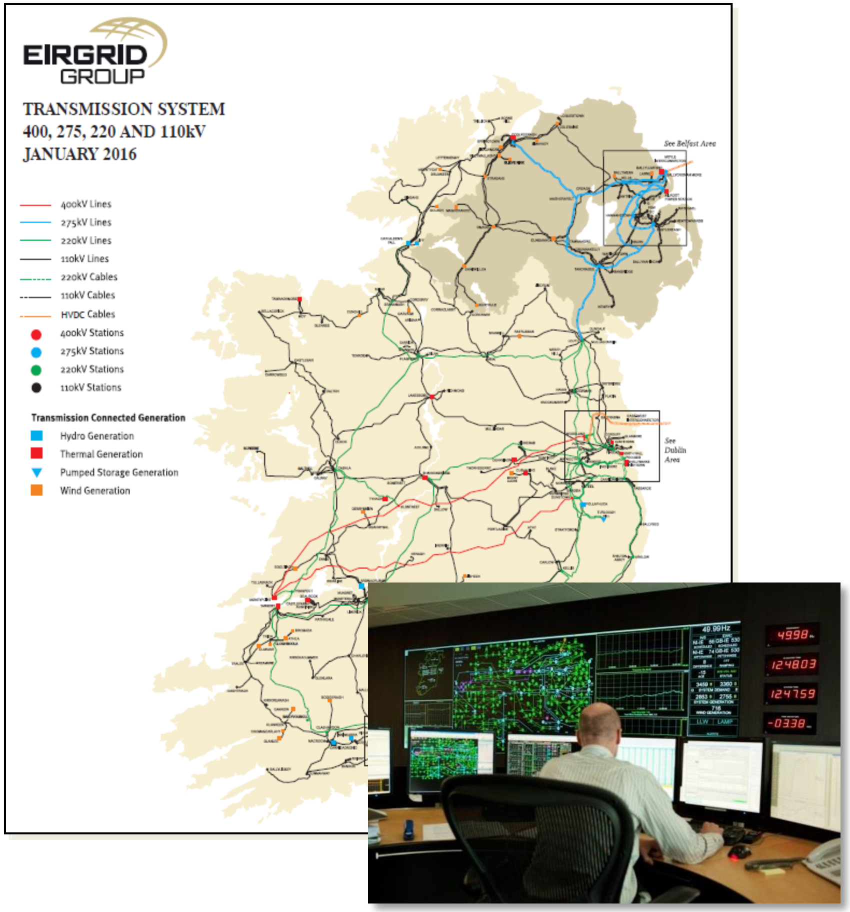
Chapter 1: Introduction



Foreword

- The Scheduling & Dispatch process is the means by which the TSOs manage the close to real-time planning and the real-time operation of units on the power system.

- This is a continuous, '24/7' process coordinated by SONI and EirGrid from the respective control centres in Belfast and Dublin using common operational systems and processes.



Overview

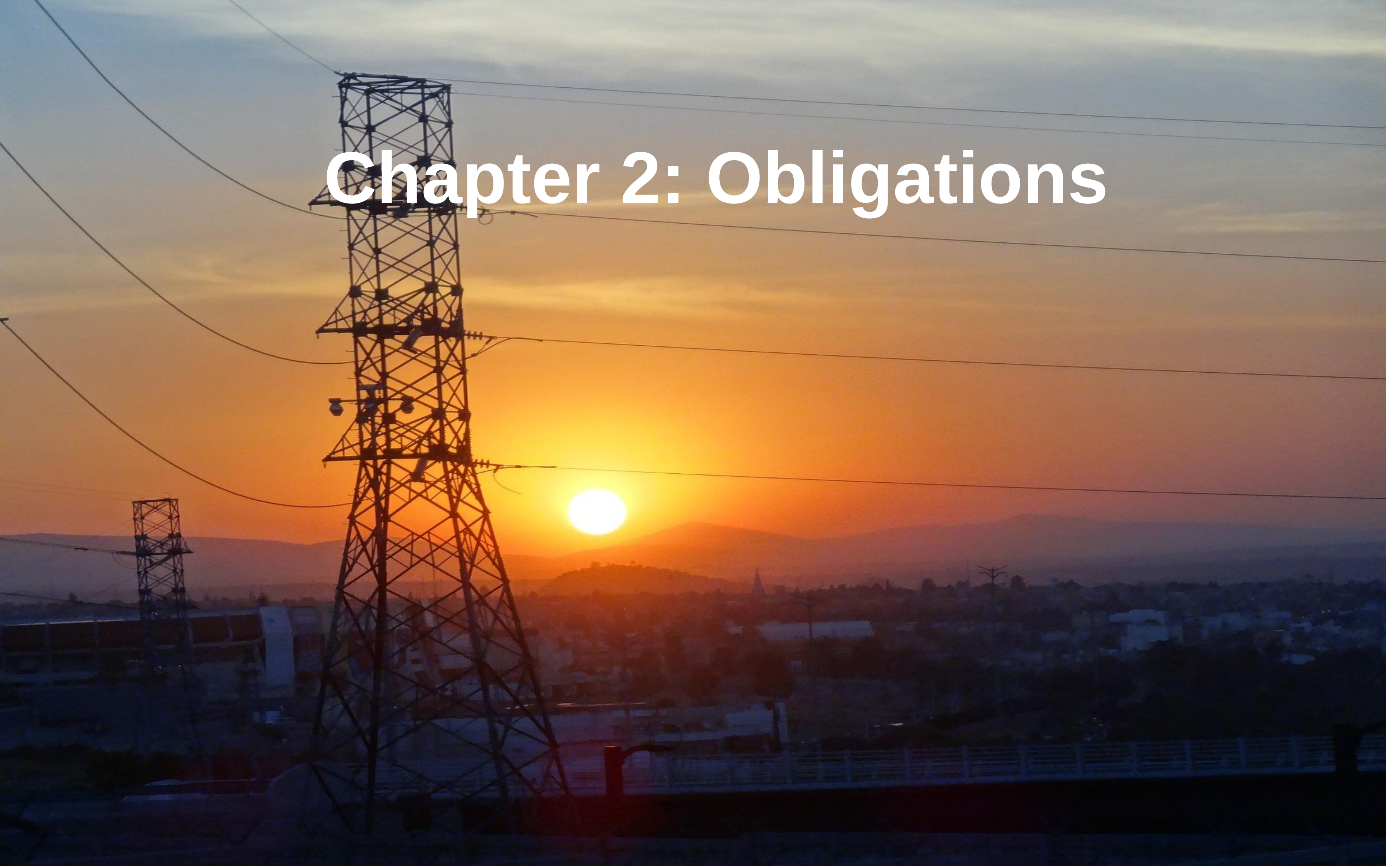
These slides describe the scheduling and dispatch process under the following headings:

- **Chapter 2 – Obligations:** This section sets out the regulatory framework (at both a European and national level) that applies to us in respect of our scheduling and dispatch activities, and also explains the interaction between these objectives.

- **Chapter 3 – Inputs:** This section sets out the market and technical inputs to the process.

- **Chapter 4 - The Scheduling and Dispatch Process:** This section sets out the process for production of Indicative Operations Schedules, the issuing of Dispatch Instructions, the provision of data to pricing and settlement systems.

Chapter 2: Obligations



Obligations – (1/2)

- This section sets out the statutory obligations under which we operate the scheduling and dispatch process. We also set out how these obligations interact and how we manage competing obligations.
- The scheduling and dispatch process operates within an obligations framework that extends from European regulations through to the Trading and Settlement Code and Grid Codes. The source of these obligations and their hierarchy of implementation in the scheduling and dispatch process are illustrated in Figure 1 below.

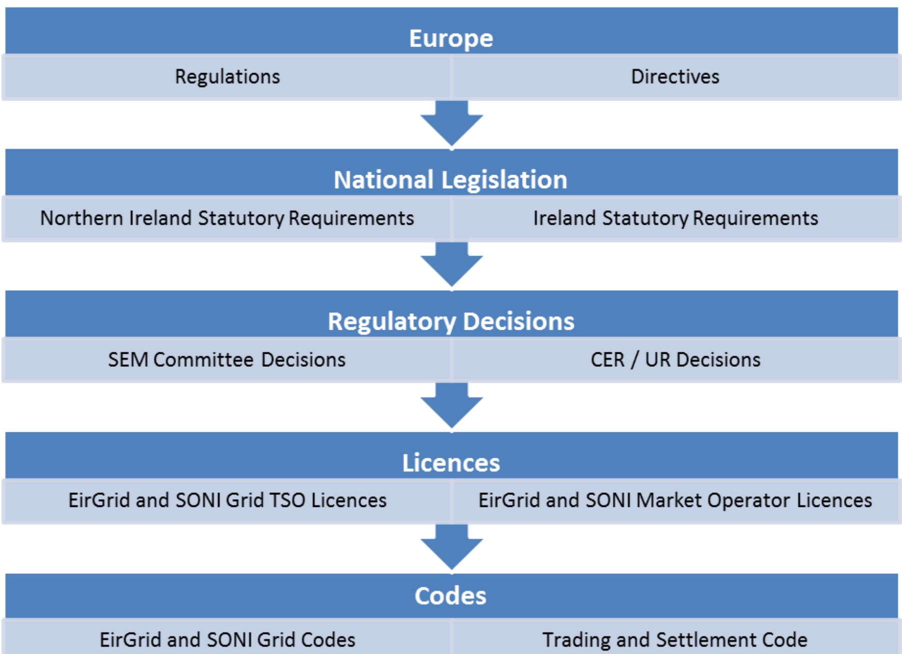


Figure 1: Obligations Framework

Obligations – (2/2)

- Our TSO Licences impose an obligation on each TSO, in conjunction with the other TSO, to schedule units and ensure direct instructions for the dispatch of units. This obligation must be carried out in accordance with the rest of the terms of each TSO Licence and the Grid Codes. This specific obligation to schedule and dispatch units is driven by our overall obligations under the broad regulatory framework illustrated above.
- In order to clearly explain our obligations to Participants, and how they interact, we have categorised them under four main headings as illustrated in Figure 2 below and described in the following sections.

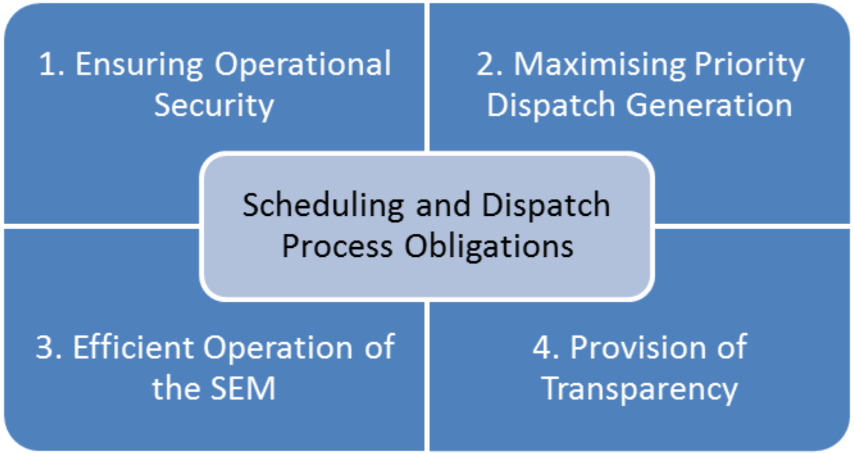


Figure 2: Scheduling and Dispatch Process Obligations

Ensuring Operational Security

- We are responsible under Article 12 of Directive 2009/72/EC of the European Parliament and of the Council concerning common rules for the internal market in electricity (the Third Electricity Directive) for ensuring the long-term ability of the system to meet reasonable demands for the transmission of electricity, operating, maintaining and developing under economic conditions secure, reliable and efficient transmission systems with due regard to the environment, contributing to security of supply through adequate transmission capacity and system reliability, and ensuring a secure, reliable and efficient electricity system.
- In addition, Commission Regulation establishing a guideline on electricity transmission system operation (once finalised) will set out minimum technical standards for the operation of power systems at a European level.
- The responsibility to ensure operational security is also provided for in national legislation, namely: (for Ireland) Regulation 8 of S.I. No 445/2000 European Communities (Internal Market in Electricity) Regulation 2000 (as amended); and (for Northern Ireland) Article 12 of the Electricity (Northern Ireland) Order 1992.
- Our obligations in respect of ensuring operational security are further reflected in our Licences, the TSC and the Grid Codes, and therefore form a key part of the scheduling and dispatch process.

Maximising Priority Dispatch Generation – (1/2)

- Article 16 of Directive 2009/28/EC of the European Parliament and of the Council on the promotion of the use of energy from renewable sources (the RES Directive) provides that Member States are required to ensure that when dispatching electricity generating installations, TSOs shall give priority to generating installations using renewable energy sources in so far as the secure operation of the national electricity system permits and based on transparent and non-discriminatory criteria.

- Article 15 of Directive 2012/27/EU of the European Parliament and of the Council on energy efficiency provides that Member States are required to ensure that, subject to requirements relating to the maintenance of the reliability and safety of the grid, based on transparent and non-discriminatory criteria set by the national regulatory authorities, TSOs when they are dispatching electricity generating installations, provide priority dispatch of electricity from high-efficiency cogeneration in so far as the secure operation of the national electricity system permits.

Maximising Priority Dispatch Generation – (2/2)

- The obligation to provide priority dispatch to certain classes of generators is also provided for in national legislation, namely: (for Ireland) Section 21 of S.I. No. 217/2002 - Electricity Regulation Act 1999 (Public Service Obligations) Order 2002 (as amended); and (for Northern Ireland) Article 11AB of the Electricity (Northern Ireland) Order 1992, which refers to the criteria set out in the SEM Committee Decision Paper SEM-11-062.

- Our obligations to provide priority dispatch to certain classes of generators are reflected in national legislation, our Licences and the Grid Codes, and form a key part of the scheduling and dispatch process.

Efficient Operation of the SEM

- We are responsible under Article 12 of the Third Electricity Directive for ensuring a secure, reliable and efficient electricity system.

- We are also responsible under Commission Regulation (EU) 2015 / 1222 establishing a guideline on capacity allocation and congestion management ("CACM") for facilitating access to cross-zonal (cross-border) exchanges of electricity and to avoid any unnecessary restriction of cross-zonal capacities.

- Under Regulation 8 of S.I. No 445/2000 European Communities (Internal Market in Electricity) Regulation 2000 (as amended), EirGrid is obliged, in discharging its functions as transmission system operator, to take into account the objective of minimising the overall costs of the generation, transmission, distribution and supply of electricity to final customers.

- In addition, we have an obligation under our Licences to establish and operate a merit order system for the balancing market which will take account of the objectives set out in each Licence, which includes minimising the cost of diverging from Physical Notifications (PNs), namely Condition 10A of EirGrid's TSO Licence and Condition 22A of SONI's TSO Licence.

Provision of Transparency

- We have a number of reporting and monitoring obligations under Regulation (EU) No 1227 / 2011 of the European Parliament and of the Council on wholesale energy market integrity and transparency (“REMIT”) and the Commission Implementing Regulation No. 1348 / 2014 (the “Implementing Regulation”). The goal of REMIT and the Implementing Regulation is to increase integrity and transparency of wholesale energy markets in order to foster open and fair competition in wholesale energy markets for the benefit of final consumers of energy.

- In addition, we are obliged to comply with other transparency measures under the Third Electricity Directive, Council Regulation (EU) 543of 2013 on submission and publication of data in electricity markets and amending Annex 1 to Regulation (EC) No 714 / 2009 of the European Parliament and of the Council, the TSO Licences, the Grid Codes and the TSC. For example, we are required to submit reports to the SEM Committee’s Market Monitoring Unit.

Competing Obligations – (1/2)

- Given the multiple sources of obligations, their range and interacting nature, we recognise that competing obligations can from time to time arise. Given the continuous, real-time nature of the scheduling and dispatch process, there must be a clear approach to prioritising these obligations to ensure that a technically feasible and consistent scheduling and dispatch solution is achieved to the maximum extent possible.

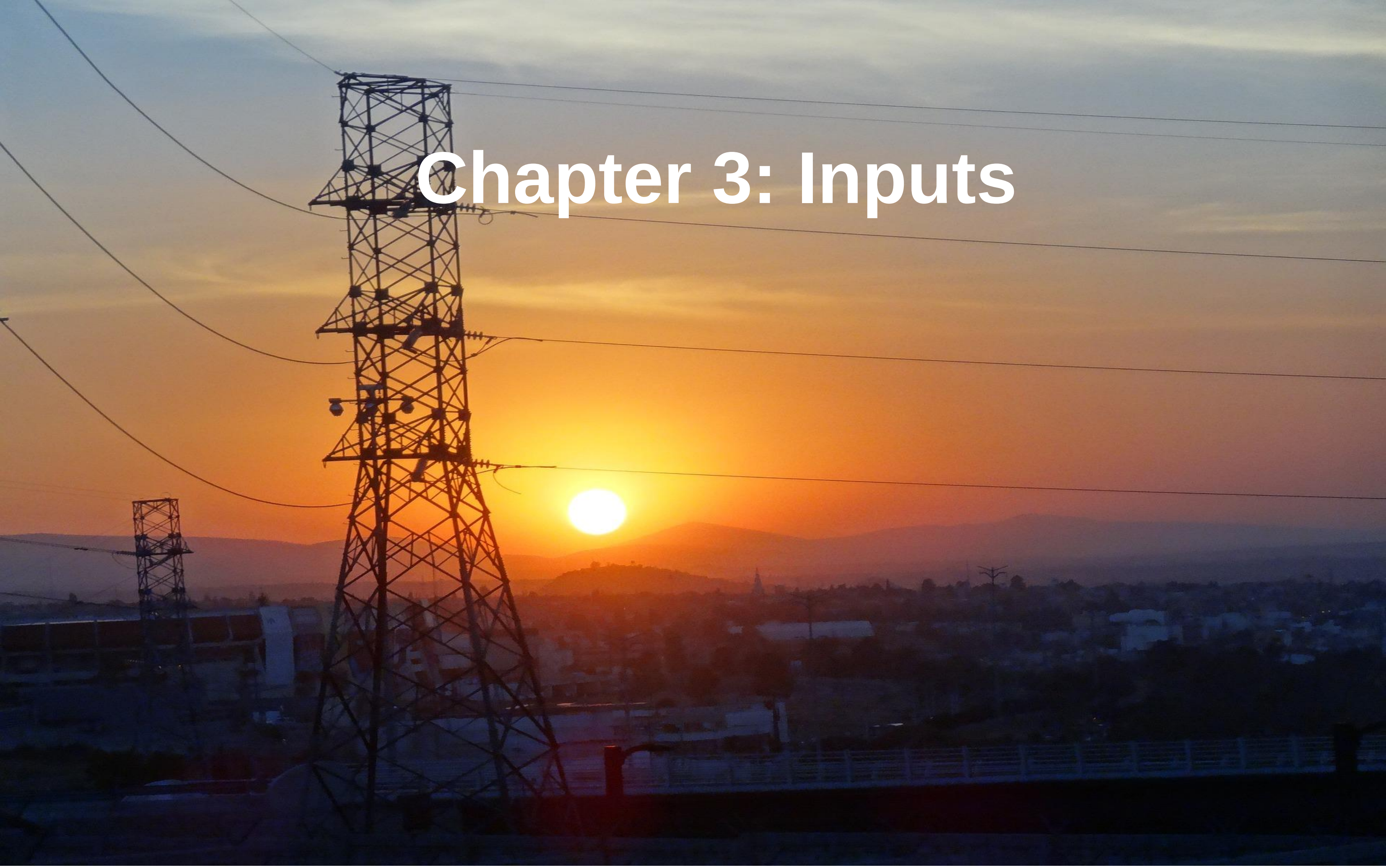
- We prioritise these scheduling and dispatch process obligations in the following order: 1. Ensuring operational security; 2. Maximising priority dispatch generation and 3. Efficient operation of the SEM (within the scheduling and dispatch process this is reflected in the objective of minimising the cost of diverging from PNs). Security is placed first as without a secure system the other obligations could not be met. Priority Dispatch is placed second, ahead of efficient (economic) operation of the SEM, on the basis of SEMC decision SEM-11-062 062 'Principles of Dispatch and the Design of the Market Schedule in the Trading and Settlement Code'. This decision states that the we must adhere to an 'absolute' interpretation of priority dispatch whereby economic factors are only taken account of in exceptional situations. At times this will result in dispatch being economically less efficient to avoid curtailment of priority dispatch generation.

Competing Obligations – (2/2)

- Within each of these three high level obligations, further ranking or weighting of obligations is required. Examples include the sub-categorisation of priority dispatch units and the weighting of economic objectives in.

- The requirement to provide transparency is an overarching obligation that does not explicitly compete with the other obligations within the scheduling and dispatch process.

Chapter 3: Inputs



Foreword – (1/2)

- This section describes the data inputs to the scheduling and dispatch process including the source of the data and how it is used.

- There are thousands of data items that form inputs to the scheduling and dispatch process. These can be categorised as commercial data (the cost of energy from each unit), technical data (the capability of each unit) as well as parameters used to implement the objectives of the process (weighting policy objectives). The data comes from various sources (from Participants and System Operators) over varying timeframes (once a day to every second) and through different interfaces (energy market and power system). The data items, grouped by source, are summarised in Figure 3 in the following slide.

- The inputs we have described in this section are associated with scheduling and dispatch under normal circumstances. Abnormal events can arise whereby different inputs are taken into account and where different scheduling and dispatch processes apply.

Foreword – (2/2)

Policy Objectives

- Priority Dispatch categorisation
- Scheduling and Dispatch Policy Parameters

Participants / System Service Providers

- Technical Data - energy market and System Services
- Commercial Data - energy market and System Services
- Physical Notifications
- Availability / System Service Capability Declarations
- Unit Under Test

Ex Ante Markets

•Interconnector Schedules

System Operators

- Demand and Renewables Forecasts
- System Constraints
- System Service Requirements
- Interconnector Technical Data
- Prices and Volumes for Cross-Zonal Actions
- Real-Time System Conditions

Figure 3: Inputs to the Scheduling and Dispatch Process

Inputs Reflecting Policy Objectives – (1/2)

Priority Dispatch

- We give priority to the dispatch of certain generation types as required by European, Ireland and Northern Ireland legislation. The output of these units is maximised as far as technically feasible. Within this categorisation there is a hierarchy of units, this is defined in SEM Committee decision SEM-11-062 with the subsequent inclusion of Solar and Tidal generation as referenced in the SEM Committee's letter to us on 24 March 2017, and as illustrated in Figure 4 on the following slide. Note that this hierarchy sits within other dispatch requirements related to hydro stations during flood risk situations, the treatment of interconnector schedules (avoiding curtailment of market schedules), other units (non-priority dispatch) and TSO led Cross-Zonal Actions over the interconnectors.

Inputs Reflecting Policy Objectives – (2/2)

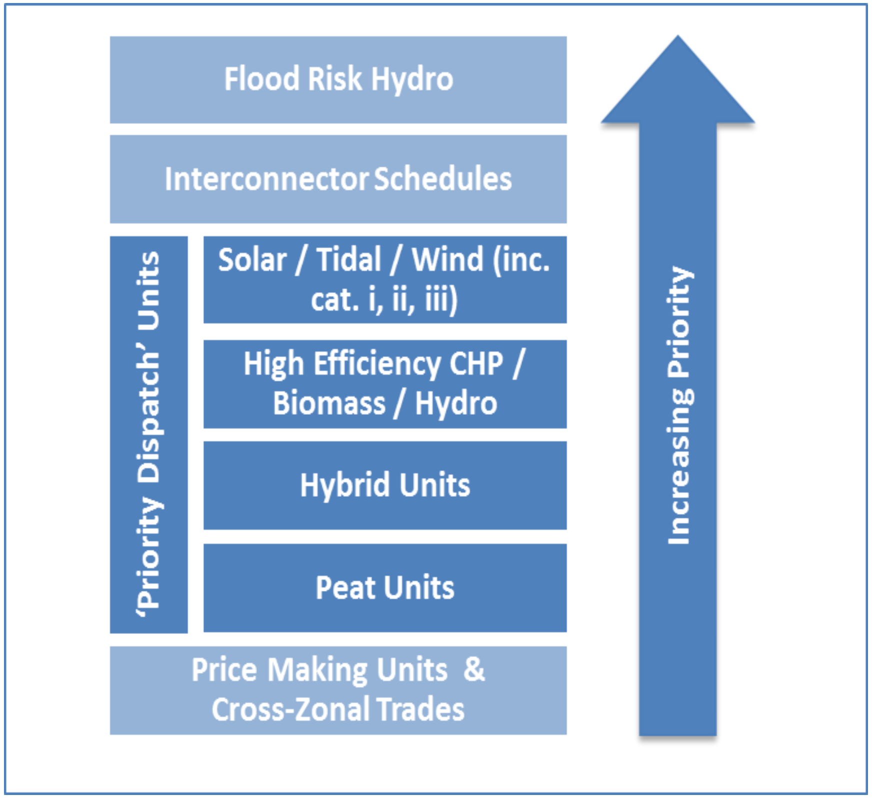


Figure 4: Priority Dispatch Hierarchy

- Within the wind category there are sub-categories reflecting the controllability of wind farms (wind farms that are controllable are given priority over wind farms that should be, but are not, controllable). Based on the guidance now provided by the SEM Committee on the treatment of Solar and Tidal units we will be updating our systems and processes to accommodate these unit types. This will include providing an update to this Controllability Categorisation process.
- We implement priority dispatch policy, and the associated hierarchy, by the application of a range of negative decremental prices to units classified as priority dispatch.

Scheduling and Dispatch Policy Parameters

Scheduling & Dispatch Policy Parameters

- Under our Licence, the RAs may determine policy parameters that apply in our scheduling and dispatch process to give effect to RA policy.

- The scheduling and dispatch policy parameters are:
  I. Long Notice Adjustment Factors (LNAF) relative to unit Notification Times;
  II. System Imbalance Flattening Factors (SIFF) relative to the System Shortfall Imbalance Index (SSII); and
  III. The Daily Time for fixing the SSII/SIFF for a Trading Day.

- Per SEM-17-046 of 7 July 2017, the SEM Committee has decided that, at go-live of the revised SEM arrangements, LNAF and SIFF will be zero and that the time to set SSII/SIFF will be determined at a later date. This decision also requires us to re-evaluate the determination of these factors in time for application from 1 January 2020.

- As these parameters will be set to zero at this time, they will have no impact on the scheduling and dispatch process and are not described further in this document.

Participants / System Service Providers – (1/2)

Participants / System Service Providers

- Technical Data - energy market and System Services
- Commercial Data - energy market and System Services
- Physical Notifications
- Availability / System Service Capability Declarations
- Unit Under Test

The following section describes Inputs provided by Participants and System Service providers.

Unit Technical Data

- TOD includes maximum and minimum output capabilities, ramp rates and notification times of units and is fundamental to the process of scheduling and dispatching units. Through the selection of predefined TOD sets, a participant can also determine their mode of operation (e.g. CCGT or OCGT mode) and/or fuel. The requirements for this data are set out in the Grid Codes SDC1 (Scheduling and Dispatch Code), TSC Part B D.3 (Timing of Data Submission), D.5 (Technical Offer Data), Appendix H (Data Requirements for Registration) H and Appendix I (Offer Data).

Participants / System Service Providers – (2/2)

- System Services data (which incorporate DS3 System Services and other System Support Services and Ancillary Services) includes operating reserve capability curves, reactive power capabilities and inertia. This data, along with TOD, is used to ensure that sufficient System Services are scheduled to meet the security requirements of the power system. The requirements for this data are set out in the Grid Codes (SDC1) and the relevant System Services agreement. This data is submitted and managed through the relevant System Services agreement and real-time declarations in our Electronic Dispatch Instruction Logger (EDIL).
- Unit technical data is used to perform validation of PNs, to develop schedules of units that utilise their technical capability to meet security and other requirements and to ensure that the dispatch of units is within their technical characteristics. We validate unit technical data through unit testing and on-going monitoring

Unit Commercial Data

- The requirements for submission of Balancing Market commercial offer data submissions are set out in Grid Codes SDC1, TSC Part B sections D.3 (Timing of Data Submissions), D.4 (Commercial Offer Data) and Appendix I (Offer Data). This commercial offer data takes two forms:
  - Complex Bid Offer Data: 3 part offer data comprising start-up, no-load and incremental and decremental price quantity pairs; and
  - Simple Bid Offer Data: incremental and decremental price quantity pairs.
- We will not make any adjustment to Participants' submitted commercial offer data even if there is a known error in this data. We will not make any adjustments in the scheduling and dispatch process for such errors. It is the responsibility of the Participant to update their commercial offer data in line with TSC rules.
- Commercial data associated with the provision of System Services does not currently form an input to the scheduling and dispatch process as each System Services considered in the scheduling and dispatch process is remunerated using common tariffs (i.e. a fixed payment rate per service is applied to each service provider). System Service providers are therefore selected based on their Balancing Market commercial offer data and their technical capability to provide a service.
- We select the appropriate commercial data set (complex or simple) for use in the scheduling and dispatch process. The objective of the scheduling and dispatch process is to minimise the cost of diverging from participants' Physical Notifications. Unit commercial data forms the basis of determining this cost.

Physical Notifications

Participants / System Service Providers

- Technical Data - energy market and System Services
- Commercial Data - energy market and System Services
- Physical Notifications
- Availability / System Service Capability Declarations
- Unit Under Test

Physical Notifications

- Physical Notifications (PNs) are submitted by Participants as their intended output excluding any accepted offers and bids (i.e. the PN does not reflect any balancing action that we take on the unit). It is Participants' responsibility to ensure that their PNs are consistent with the Technical Offer Data for their units.
- All dispatchable Participants are required to submit PNs. Non-dispatchable Participants will not be obliged to submit PNs (even if they have traded or expect to trade in the markets) but may elect to do so for information purposes. We will use our own forecasts of their output as an implicit PN for these non-dispatchable units.
- A unit's PN is used along with its incremental and decremental cost curves to form a composite cost curve that is used within the scheduling and dispatch process. PNs for units under test are also flagged to ensure that the PN is prioritised within the scheduling and dispatch process.

Availability and System Services Capability Declarations – (1/2)

Participants / System Service Providers

- Technical Data - energy market and System Services
- Commercial Data - energy market and System Services
- Physical Notifications
- Availability / System Service Capability Declarations
- Unit Under Test

Availability and System Services Capability Declarations

- Participants are required to submit and maintain forecast active power (MW) availability for their units with real-time updates provided as this information changes. Updates to System Service capabilities are also required from System Service providers.

- Forecast availabilities submitted by Participants via the BMI are:

  I. a Forecast Availability Profile;

  II. a Forecast Minimum Output Profile; and

  III. a Forecast Minimum Stable Generation Profile

Availability and System Services Capability Declarations – (2/2)

- Real-time availability declarations are also provided by Participants via EDIL interface with the TSOs. Requirements for real-time availability declarations are set out in Grid Codes SDC1.
- It is the responsibility of Participants to ensure that forecast availability aligns with real-time availability declarations in EDIL. For example, if a unit trips, the Participant will re-declare its availability to zero in EDIL and, if appropriate, update the forecast availability via the BMI in line with the allowed forecast availability submission window.
- Non-dispatchable wind units provide a real-time availability signal via our Energy Management System (EMS). Forecast availability for non-dispatchable wind comes from our wind forecast.
- For dispatchable units, real-time System Services declarations such as reactive power or operating reserve capabilities can be made in real-time via EDIL. Requirements for the declaration of System Services are set out in Grid Codes SDC1. Any longer term changes to System Service capability are managed through the respective System Services agreement in place with each System Service provider.
- We select the appropriate availability data (forecast or real-time) for use in the scheduling and dispatch process. Unit availability data determines the technical capability range available to be utilised in the scheduling and dispatch process. The approach for solar generation is expected to follow the wind model. We are currently developing these arrangements.

Unit Under Test Notification

Participants / System Service Providers

- Technical Data - energy market and System Services
- Commercial Data - energy market and System Services
- Physical Notifications
- Availability / System Service Capability Declarations
- Unit Under Test

Unit Under Test Notification

- To facilitate unit testing which requires a specific running profile, Participants submit PNs via the BMI specifying the period that the unit is requested to be under test with a test flag. Any PN submission that includes a PN with a test flag will require manual approval by the TSO before it is accepted in to the scheduling and dispatch systems. Any subsequent modifications to a test PN, including cancellation is also subject to our approval.
- The type of test being requested by a unit will determine the notification time required by us to assess and approve a test and incorporate into the scheduling and dispatch process. The Grid Codes set out definitions for the categorisation of tests as either a Significant Test or a Minor Test (OC8 in the EirGrid Grid Code, and OC10 and OC11 in the SONI Grid Code).
- We will prioritise a unit under test in the scheduling and dispatch process so that its PN is respected as far as technically feasible.

Ex-Ante Market Interconnector Schedules

Ex Ante Markets

- Interconnector Schedules

Interconnector Schedules

- Interconnector schedules are an output of each ex-ante market. These are notified to us following completion of the day-ahead market with updates following as a result of intraday trading.

- Interconnector schedules are represented as fixed demand and/or generation profiles within the scheduling and dispatch process.

System Operator Inputs

System Operators

- Demand and Renewables Forecasts
- System Constraints
- System Service Requirements
- Interconnector Technical Data
- Prices and Volumes for Cross-Zonal Actions
- Real-Time System Conditions

- System operators referred to in this section are: the Distribution System Operator (DSO) in Ireland (ESB Networks Designated Activity Company) and the Distribution Network Operator (DNO) in Northern Ireland (Northern Ireland Electricity Limited), the GB TSO (National Grid plc), the Interconnector Owners ICOs (Mutual Energy Limited and EirGrid Interconnector Designated Activity Company) and the TSOs in Ireland and Northern Ireland (EirGrid and SONI).

Demand Forecast – (1/2)

System Operators

- Demand and Renewables Forecasts
- System Constraints
- System Service Requirements
- Interconnector Technical Data
- Prices and Volumes for Cross-Zonal Actions
- Real-Time System Conditions

Demand Forecast

- We produce demand forecasts representing the predicted electricity production required to meet demand including system losses but net of unit demand requirements ('house-load').
- The forecasts are based on historical jurisdictional data for total generation (conventional and wind). The total generation is used as a proxy for the total demand. The forecasts for each jurisdiction are calculated separately due to the different demand profiles in Ireland and Northern Ireland, and to reflect the differences in some bank holidays and special days. The forecast only reflects the generation visible to us via SCADA, so deeply embedded generation or micro-generation is not factored in. The forecasts themselves are produced using a proprietary software package. The algorithm learns the relationship between the system demand and a set of predictor variables (day of week, time of day, week of year, special days, average hourly temperature) based on historical data. It then creates a prediction for each half hour of the forecast period.

Demand Forecast – (2/2)

- We produce a 5 day demand forecast at half hour resolution on a daily basis. We then update this forecast on a continuous basis to account for actual demand conditions and interpolate the forecast to a 1 minute resolution for use in the scheduling and dispatch process.

- Demand forecasts are produced in line with Grid Code obligations - OC1.6 in the EirGrid Grid Code and OC1.5 in the SONI Grid Code.

- In our scheduling process we develop plans that schedule sufficient generation to meet our demand forecast.

Renewables Forecast – (1/2)

System Operators

- Demand and Renewables Forecasts
- System Constraints
- System Service Requirements
- Interconnector Technical Data
- Prices and Volumes for Cross-Zonal Actions
- Real-Time System Conditions

Renewables Forecast

- We procure wind power forecasts from two forecast providers. These forecasts include the forecast power output from each wind farm greater than or equal to 5 MW along with the total aggregate forecast power production and an uncertainty of the aggregate power forecast. Standing data, such as location, turbine number, type and model and hub height, for each wind farm is provided to the wind forecast providers. In addition, meteorological measurements and SCADA from each site (where available) are sent to the providers on an ongoing basis. This information is used by the wind forecast providers to develop and train models for each wind farm. Numerical Weather Predication models along with the developed wind power prediction models are then used to produce the wind power forecasts.

- Wind forecasts do not include curtailment forecast as these are only implemented in real-time operation. The forecast providers are supplied with wind farm outages information where these are available.

Renewables Forecast – (2/2)

- Each forecast provider provides us with a forecast every 6 hours, at 15 minute resolution with a time horizon of 120 hours. We then merge these forecasts, blend them with current wind conditions on a continuous basis and interpolate to a 1 minute resolution for use in the scheduling and dispatch process.

- Note that while wind participants may submit PNs representing their forecast production, these are not used in the scheduling and dispatch process. Rather we develop schedules that utilise our own forecast of renewables. This approach is driven by the Priority Dispatch categorisation of renewable generation.

- The impact of solar generation is becoming increasingly significant on the operation of the power system so we are currently developing our forecasting capability in this area. We will provide updates on this development as appropriate.

Constraints – (1/2)

System Operators

- Demand and Renewables Forecasts
- System Constraints
- System Service Requirements
- Interconnector Technical Data
- Prices and Volumes for Cross-Zonal Actions
- Real-Time System Conditions

Constraints

- Constraints impose limits on the physical operation of units in order to maintain operational security requirements under normal and contingency (failure of an item of equipment, e.g. transmission line or unit) conditions. An illustration of some of the constraints on the Ireland and Northern Ireland power system is provided (see figure 5).

Reserve (Frequency Limits)	Thermal	Voltage	Dynamic Stability
• All Island OR Requirement	• North-South Tie-Line Limit	• Coolkeeragh Must Run	• Inertia
			• RoCoF*
• NI / IRL Min OR Requirement	• Ballylumford Export Limit	• Kilroot Must Run	• SNSP*
• NI / IRL RR (OCGT) Limitation	• Various Dublin Must Run	• Various Dublin Must Run	• NI 3 Units Must Run
• NI / IRL Negative Reserve	• Cork Export limit	• South West Must Run	• IRL 5 Units Must Run
• Ramping		• Moneypoint Must Run	

*RoCoF: Rate of Change of Frequency
*SNSP: System Non-Synchronous Penetration

Figure 5 Illustration of Power System Constraints

Constraints – (2/2)

- In real-time operation of the power system there is a need to respond to forced outages or unexpected constraints as it is not possible for all scenarios to be covered in the weekly look-ahead analysis. We perform security analysis every five minutes which considers circuit loadings, system voltages and transient stability for a range of contingencies. This real-time analysis runs in parallel with the scheduling and dispatch and may result in constraints arising that are not reflected in the schedules.

- Constraints may also arise on distribution network connected units. Where such constraints impact on the our ability to dispatch/control units, the relevant DSO/DNO will inform us so that the constraint is reflected in the scheduling and dispatch process.

- Participants' PNs are not required to respect these constraints (only the physical constraints of the units themselves) so a key aspect of the scheduling and dispatch process is the application of these constraints to the PNs to produce a schedule and dispatch that is physically secure. Constraints modelled in the scheduling tools also form a key input to the Imbalance Pricing process through the setting of System Operator Flags.

System Service Requirements

System Operators

- Demand and Renewables Forecasts
- System Constraints
- System Service Requirements
- Interconnector Technical Data
- Prices and Volumes for Cross-Zonal Actions
- Real-Time System Conditions

System Service Requirements

- The provision of System Services (such as operating reserves and reactive power) from service providers is required to support the secure operation of the power system. We specify the requirement for System Services in a number of ways:
  I. 'must run' requirements to support the provision of reactive power from units in particular locations on the power system,
  II. relatively static system requirements such as the minimum system inertia level,
  III. dynamic requirements for operating reserves which are a percentage of the Largest System Infeed (LSI) on the system.

- We publish requirements for the System Services modelled in the scheduling and dispatch process in our Operational Constraints Update.

Interconnector Technical Data

System Operators

- Demand and Renewables Forecasts
- System Constraints
- System Service Requirements
- Interconnector Technical Data
- Prices and Volumes for Cross-Zonal Actions
- Real-Time System Conditions

Interconnector Technical Data

- The ability to transfer power over the interconnectors is a function of the capacity of the interconnectors and the capacity of the transmission systems on either side. We co-ordinate the setting of the interconnection capacities with the ICOs and GB TSO. These capacities feed into the ex-ante markets and the scheduling and dispatch process.
- We are currently developing a Cross-Zonal Capacity Calculation process for determining the interconnection capacities between the markets with the SEM and BETTA Regulatory Authorities.. This document is expected to be published prior to market trial.
- The determined capacities are provided to the ex-ante markets as the limits to allowable cross-zonal (between SEM and BETTA) exchanges of power. We also use these capacities in the scheduling and dispatch process to determine available capacity for Cross-Zonal Actions.
- We set the operational ramp rate applied to each interconnector. This is a MW/min ramp rate that is applied in the physical dispatch of each interconnector.
- The interconnectors can also provide a number of System Services. These capabilities are as agreed in the relevant System Services agreement that we have in place with the ICOs.

Prices and Volumes for Cross-Zonal Actions – (1/3)

System Operators

- Demand and Renewables Forecasts
- System Constraints
- System Service Requirements
- Interconnector Technical Data
- Prices and Volumes for Cross-Zonal Actions
- Real-Time System Conditions

Prices and Volumes for Cross-Zonal Actions

- While interconnector (Moyle and EWIC) schedules are determined by the ex-ante markets, they can, under defined circumstances, be adjusted by us through Cross-Zonal Actions. Cross-Zonal Actions is the collective name for a number of services that are available to us to reduce or increase imports or exports on the interconnectors.

- **Note**: We are currently developing the services that will be available for application under the revised SEM arrangements (subject to RA consideration). The arrangements will include the specific services that will be made available, arrangements for determining and exchanging offered energy volumes and associated prices and how such services are utilised.

Prices and Volumes for Cross-Zonal Actions – (2/3)

The table below describes the existing Cross-Zonal arrangements in place.

Cross-Zonal Action	Description
Trading Partner	We have trading arrangement in place with a BETTA trading partner that allows us to trade in the gap between closure of the existing SEM market and the BETTA market. This is the main route available to us for trading under the existing SEM arrangements. This mechanism is used for facilitating Priority Dispatch (increasing exports to GB rather than curtailing wind generation in SEM) and management of system constraints (such as reducing interconnector imports or exports to manage the interconnector as a largest system infeed or outfeed thus reducing reserve requirements).
Cross-Border Balancing – CBB	We have trading arrangements in place with the GB TSO. We exchange offers and bids for volumes of energy and prices on a daily basis however the service is only available on a rolling 1 to 2 hour timescale from real-time (post BETTA Balancing Market gate closure). Given the tighter timescales of this service and the availability of the existing Trading Partner arrangements, this CBB mechanism is not frequently used by us or the GB TSO.
Emergency Assistance - EA	We have an Emergency Assistance arrangement in place with the GB TSO. This service is an emergency service that allows either party to request emergency cross-zonal assistance from the other party. The service would be utilised during capacity shortfall scenarios. A fixed price is agreed by us in advance (although any higher CBB price would apply if the service was activated) and a fixed volume is made available.
Emergency Instruction - EI	We have an Emergency Instruction arrangement in place with the GB TSO. This service is an emergency service that allows either party to instruct a reduction in interconnector flow towards zero. The service would be utilised during an operational security event such as a circuit overloading and results in the application of a reduced Net Transfer Capacity (NTC) on the interconnector.

Note: These arrangements remain under review and are subject to change.

Prices and Volumes for Cross-Zonal Actions – (3/3)

- Any utilisation of Cross-Zonal Actions takes place after closure of the cross-zonal markets. Cross-Zonal Actions utilise spare interconnector capacity – they do not restrict the interconnector capacity offered to the markets or undo the market position of Participants.

- Depending on the arrangements ultimately developed, the prices and volumes of energy offered as part of the non-emergency actions may form an input to the scheduling and dispatch process.

Real-Time System Conditions

System Operators

- Demand and Renewables Forecasts
- System Constraints
- System Service Requirements
- Interconnector Technical Data
- Prices and Volumes for Cross-Zonal Actions
- Real-Time System Conditions

Real-Time System Conditions

- We collect information on the real-time status of the power system via our Energy Management System (EMS) and Supervisory Control and Data Acquisition (SCADA) system. This information includes:
  I. the status of transmission circuits being in or out of service,
  II. the status of units (on/off)
  III. power-flows on circuits and interconnectors
  IV. real-time demand
  V. real-time wind output
  VI. system voltages
  VII. system frequency

- Our scheduling process takes 'snapshots' of the real-time status of the power system so that the most up to date system conditions, along with forecast conditions, are modelled in our scheduling systems.

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Chapter 4: The Scheduling and Dispatch Process

Foreword

- Our scheduling and dispatch process incorporates a range of activities associated with managing the close to real-time planning and operation of the power system.

- This process is designed to implement European and jurisdictional policy objectives based on a range of market and technical inputs. This is achieved through: the production of Indicative Operations Schedules; the issuing of dispatch instructions; the provision of data to pricing and settlement systems and information to support various reporting mechanisms and

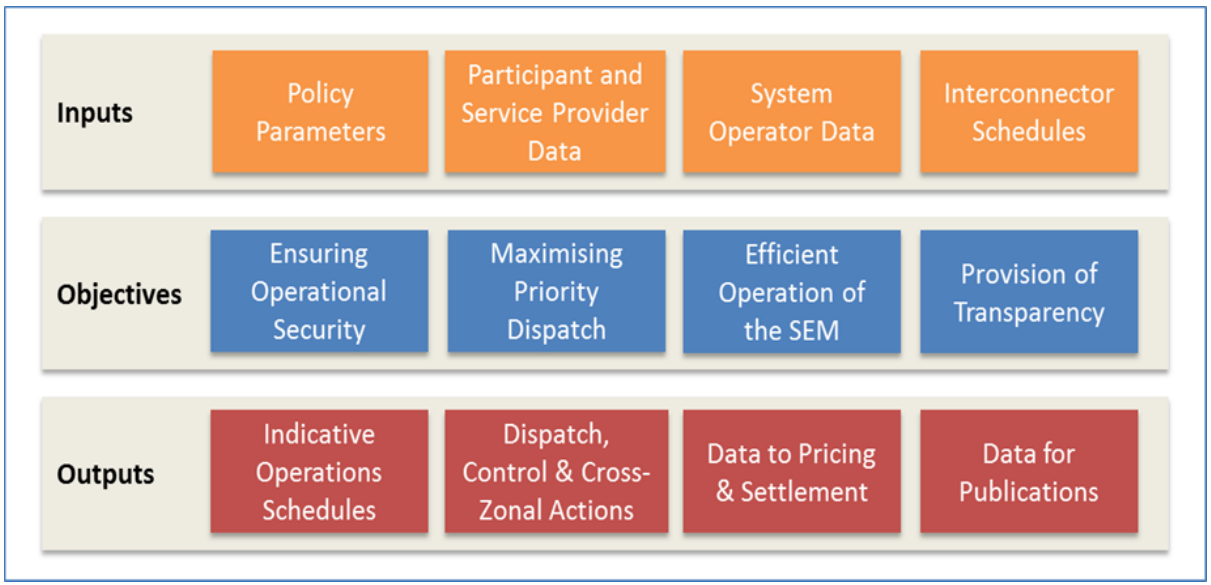

Figure 6 Overview of the Scheduling & Dispatch Process

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Process Overview – (1/2)

- The scheduling and dispatch process is built around the Balancing Market which is the sole mechanism by which we dispatch units to manage constraints, provide System Services and dispatch balancing energy.

- The Balancing Market requires Participants to submit PNs with COD, representing their incremental and decremental costs to move from this position, by Gate Closure of the Trading Day (13:30 day-ahead). Participants can update their PNs and COD after this time and up to Gate Closure of the Imbalance Settlement Period to reflect their intraday trading activity or any update to their balancing offers and bids. These offers and bids form the basis of our ability to efficiently position units to provide System Services, manage system constraints and dispatch energy balancing actions.

- Conditions on the power system can change from what was forecast (demand and wind variations), and transmission circuit and unit availability can change in an unplanned manner. We operate a continuous scheduling process to ensure the latest market and system information feeds into the actual dispatch. The continuous nature of the process means that whenever a dispatch instruction is issued, it will be on the basis of the latest market positions, the latest notification of unit capabilities and the latest actual and forecast system conditions.

Process Overview – (2/2)

- Our scheduling and dispatch process operates from real-time through to the next Trading Day. Given the volume of inputs to the process and the complex nature of the process itself, it is split into a number of timeframes that allow for short term analysis to be performed quickly and regularly while longer term analysis, which takes more time to process, is performed less frequently. The aim is to achieve a rolling, integrated and current plan of actions.

- The scheduling and dispatch run types are summarised on the next slide. Each of these run types operate over a different timeframe and uses different inputs as a result. Each run type uses either Security Constrained Unit Commitment (SCUC) or Security Constrained Economic Dispatch (SCED) algorithms. The output of each of these runs is an Indicative Operations Schedule (IOS) of unit production and consumption (of storage units and demand side units rather than supplier units) levels (MW levels per scheduling time interval) that meet the objectives of the scheduling and dispatch process.

Scheduling & Dispatch Run Types

LTS – Long-Term Schedule

- Provides medium to long-term Security Constrained Unit Commitment (SCUC) schedules.
- Runs every 4 hours. Produces a schedule from initiation time +4 hours for a duration of up to 30 hours (horizon depends on purpose and timing of the run).
- The scheduling interval is 30 mins (i.e. a MW value for each unit is determined for each hour and half hour over the horizon).
- Output is an IOS (Indicative Operations Schedule) that is used to inform unit commitment instructions, of the form 'sync and go to minimum load' or 'desync', which are issued in line with unit notification times.

RTC - Real-Time Commitment

- Provides short term Security Constrained Unit Commitment (SCUC) schedules.
- Runs every 15 minutes. Produces a schedule from initiation time +30 mins for a duration of 3½ hours.
- The scheduling interval is 15 mins (i.e. a MW value for each unit is determined every 15 mins over the horizon).
- Output is an IOS that is used to inform unit commitment instructions, of the form 'sync and go to minimum load' or 'desync' which are issued in line with unit notification times.

RTD - Real-Time Dispatch

- Provides Security Constrained Economic Dispatch (SCED) schedules close to real time consisting of incremental and decremental MW schedules.
- Does not make unit commitment / de-commitment decisions but accounts for these decisions which come from RTC and LTS.
- Runs every 5 minutes. Produces a schedule from initiation time +10 mins for a duration of 60 mins.
- The scheduling interval is 5 mins (i.e. a MW value for each unit is determined every 5 mins over the horizon).
- Output is an IOS that is used to inform dispatch instructions of the form 'go to x MW' which are issued in line with unit ramping capability.

Illustrative Scheduling and Dispatch Run Sequence

- These schedules are run automatically and continuously as illustrated in Figure 7 below. Manually initiated LTS runs can also be performed to consider significant changes to inputs (such as a forced outage of a large unit) so that we can, if necessary, update our plans to ensure that, for example, system security requirements are met.

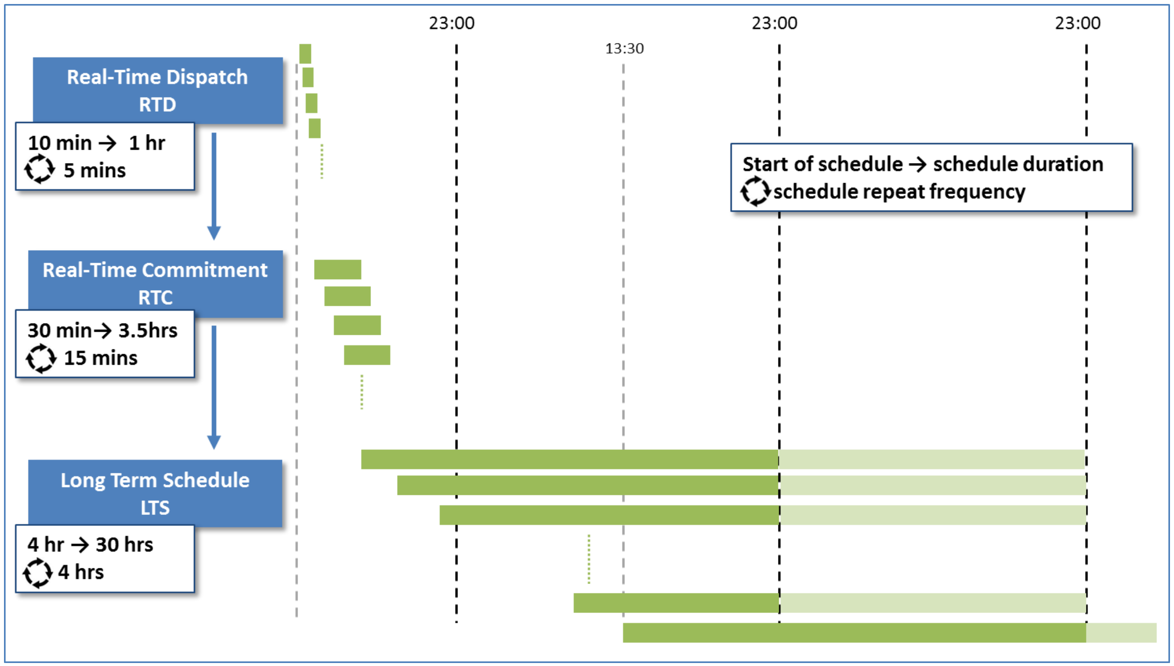

Figure 7 Illustrative Scheduling & Dispatch Run Sequence

- In addition to the production of IOSs, the process produces merit orders of available actions that we can take to increment / start-up units or decrement / shut-down units in response to changing system conditions that may not have been factored into the IOS (e.g. a deviation from forecast wind levels or a unit trip that requires fast start units to be started up).

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SCUC & SCED

- Scheduling is an highly complex task, taking many diverse inputs in terms of data and objectives to produce IOSs. Complex mathematical programs are used for these purposes. These programs employ optimisation techniques to simplify the scheduling problem so that it can be determined within the time restrictions of real-time operations. This is because, with the scale of the problems to be solved, “brute force enumeration”, where every possible outcome is tested is not feasible.

- The optimisation programs used to produce IOSs are known as Security Constrained Unit Commitment (SCUC) and Security Constrained Economic Dispatch (SCED).

- The purpose of SCUC is to determine the commitment status of units, i.e. whether or not a unit is on (synchronised) or off (de-synchronised) and the schedules of units, i.e. their indicative MW output level at instances in time, at least cost while respecting technical constraints and other policy objectives.

- SCED does not make unit commitment decisions (it takes these from SCUC) but optimises the MW schedules of units already committed or scheduled to be committed. Like SCUC, its objective is to schedule at least cost while respecting technical constraints.

Data Preparation

- Some of the data items described in the inputs section are processed / selected to facilitate the scheduling process as described in the following sections.

Availability Data Selection

- Both forecast availability and real-time availability of units form inputs to the process (as described in the Inputs section). For the same unit, real-time availability can differ from the forecast availability (say due to a unit trip) so the scheduling run types use the following sources of unit availability data.

Scheduling Run Type	Source of Unit Availability	
	Dispatchable Unit	Wind
LTS – Long-Term Schedule	Forecast availability as submitted via the BMI	Per TSO wind forecast
RTC – Real-Time Commitment	Forecast availability as submitted via the BMI or real-time availability as declared in EDIL	Per TSO wind forecast blended with real-time availability from EMS
RTD – Real-Time Dispatch	Real-time availability as declared in EDIL	Per TSO wind forecast blended with real-time availability from EMS

Commercial Offer Data Selection

- Participant commercial offer data submissions can be in complex and simple formats as described in the Inputs section. This data is applied in each of the scheduling run types as described in the table below.

Scheduling Run Type	Source of Commercial Data		
	Primary	Back-Up 1	Back-Up 2
LTS – Long-Term Schedule	Complex	Default	N/A
RTC – Real-Time Commitment	Complex	Default	N/A
RTD – Real-Time Dispatch	Simple	Complex*	Default*

*Note: only inc/dec component of complex or default commercial offer data is used
The Back-up sources are utilised if the primary source of commercial data is not available.
Arrangements for the submission of default commercial offer data are set out in the TSC Part B section D.

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Composite Cost Curve – (1/2)

- The complex and simple commercial offer data submitted by Participants contains two separate Price/Quantity (PQ) curves based on absolute MW; one containing a range of break points and incremental prices, the other containing a range of break points (not necessarily the same) and decremental prices. Within the scheduling process, for each Imbalance Settlement Period, for each unit, a composite PQ curve is created by using the PN value to combine the two curves as described below:

- All segments from the decremental curve where the MW range is below or equal to the PN; and

- All segments from the incremental curve where the MW range is above or equal to the PN.

Composite Cost Curve – (2/2)

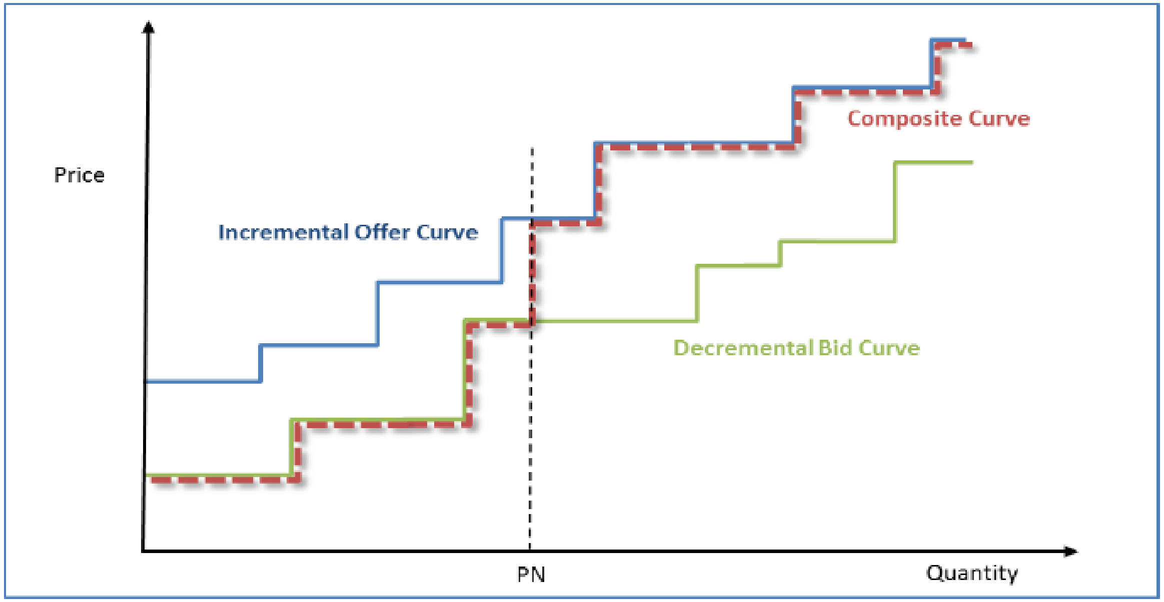


Figure 8 Illustration of Composite Cost Curve

- This composite curve (the red dashed line in the Figure above) for each unit, for each Imbalance Settlement Period is used within the scheduling tool as the cost curve used to make incremental and decremental adjustments within the optimisation.

Conversion of Interconnector Schedules to Reference Programmes

- The Moyle and EWIC interconnector schedules that are provided to us are block schedules – hourly for the day-ahead market, half-hourly for intraday updates. While the interconnectors are physically capable of achieving rapid changes between trading periods, a ramping rate is applied to ensure that changes to the physical interconnector flows respect the relatively slower ramping capability of units on the system and the slower rate of change in demand and wind production levels. Rapid changes to interconnector schedules could otherwise result in disturbances on the power system.

- We convert the block schedule for each interconnector to a physical Interconnector Reference Programme (ICRP) that describes the point in time flow on the interconnector and which respects the operational ramp rates applied to each interconnector. The conversion of the block market schedule to an ICRP is illustrated in Figure 12 below. This conversion process seeks to minimise the energy volume difference between the ICRP and the block market interconnector schedule so as to minimise any energy imbalance that arises over the Trading Day. In the Figure below this imbalance is represented as the net area within each imbalance settlement period between the ex-ante market interconnector schedule and the ramp limited ICRP.

Conversion of Interconnector Schedules to Reference Programme Illustration – (1/2)

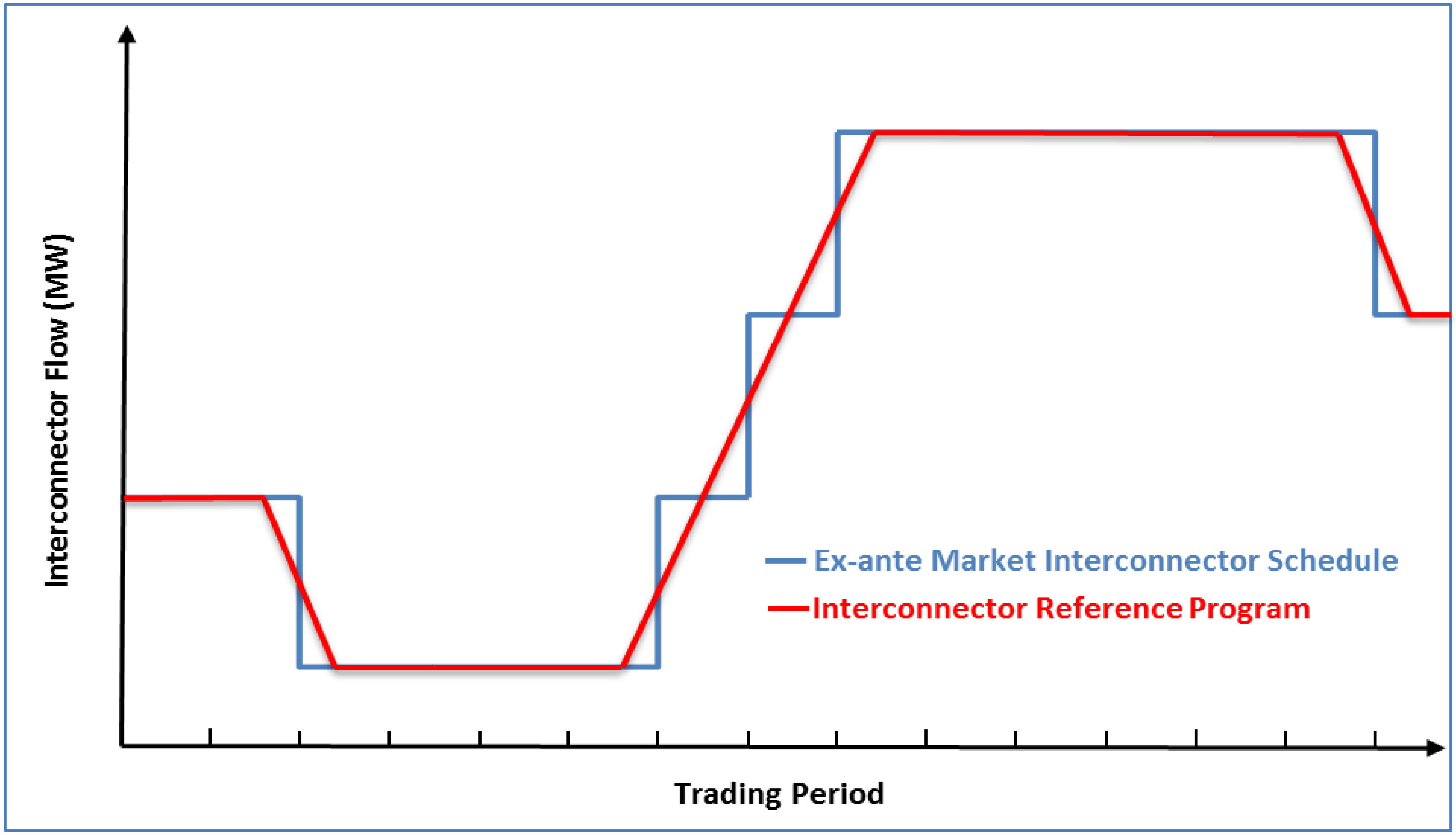


Figure 9 Conversion of Block Market Schedule to ICRP

Units Under Test

- Units that we approve to be under test (having provided the required notice as set out in the Grid Codes) will be scheduled and dispatched according to their submitted test PNs as far as secure operation of the power system allows.

- Participants may also submit offers and bids with their Test PN although these will not normally be utilised in the scheduling and dispatch tools during the test period (as the units is fixed to its PN). However, in the event of an operational security issue arising, we may override the scheduling process and manually dispatch a unit away from its test profile. In such an event, the applicable commercial offer data will apply to the settlement of our action (acceptance of a bid or offer) as any other bid-offer acceptance.

Cross-Zonal Actions

- The scheduling tool can be configured to either leave the ICRP unadjusted from the position determined from the ex-ante market schedule (i.e. no consideration of Cross-Zonal Actions) or to allow adjustment of the ICRP to facilitate priority dispatch for example.

Note: These arrangements remain under review and are subject to change.

The Optimisation – (1/2)

- The underlying optimisation objective is to minimise the cost of diverging from PNs. This objective is bound by the need to respect security constraints, maximise priority dispatch generation and to weight the schedule towards shorter notice dispatch actions. By assigning constraint violation costs and substituting commercial offer data within the optimisation, a schedule can be developed which minimises the cost of diverging from PNs (as seen by the optimiser rather than 'real' costs) but still satisfies these constraints and policy objectives. The mechanisms by which these requirements are reflected in the optimisation and their hierarchy is illustrated in the Figure on the next slide.

- Note that this optimisation objective is different to the objective in the current SEM market. In the current SEM, the objective is to minimise the cost of production based on the commercial offer data provided by Participants. The optimisation does not take into account the market position of Participants. Under the revised SEM arrangements, the schedule seeks to minimise the cost of moving away from Participants' intended running position as reflected in their PN.

The Optimisation – (2/2)

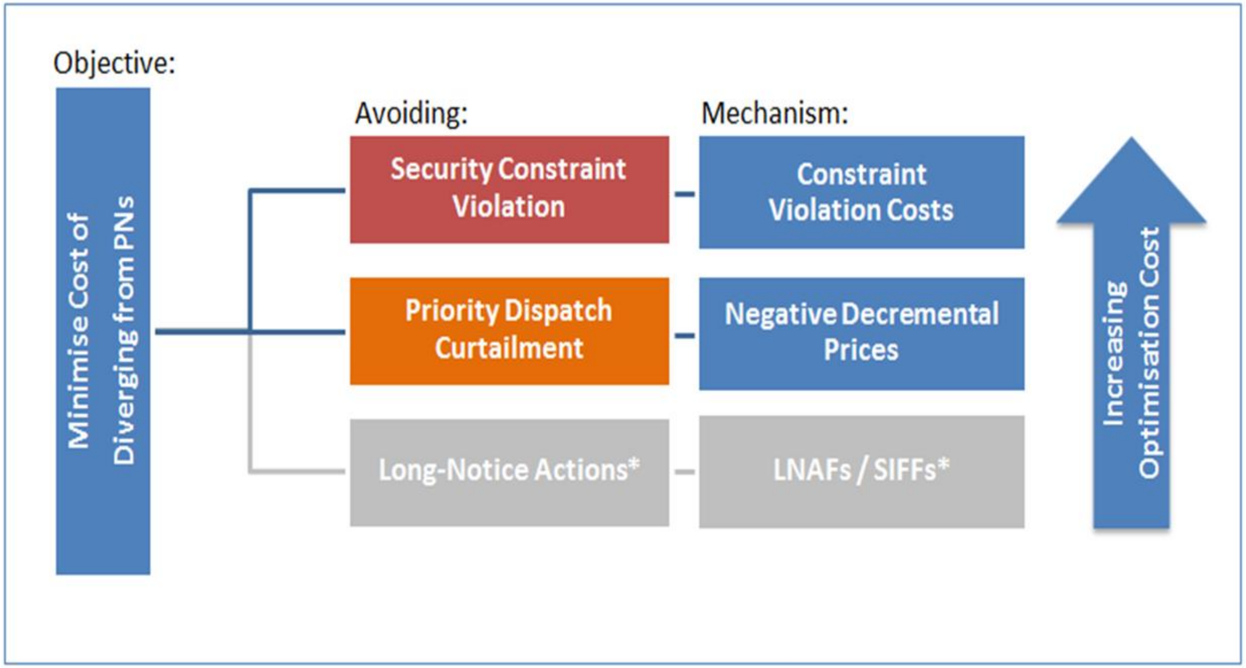


Figure 10 Illustration of Optimisation Objectives

(*not being implemented at go-live of the revised SEM arrangements)

Security Constraints

- Each constraint type is assigned a constraint violation cost which is incurred if the constraint is breached within the optimisation cycle. This cost deters the optimisation from breaching a constraint as to do so would result in a higher apparent cost within the optimisation. These constraint violation costs are parameters within the optimisation that we can tune to give effect to each constraint. In principle all constraints are absolute requirements which must be respected.

Priority Dispatch – (1/2)

- We assign priority dispatch status in the scheduling and dispatch process by allocating a range of pre-determined negative decremental prices to the units defined as priority dispatch (see Inputs section). These prices reflect their relative position in the priority dispatch hierarchy – the higher the priority the more negative the decremental price. Any submitted decremental price is substituted by this predefined priority dispatch price for the purpose of the optimisation however this replacement price does not feed into pricing or settlement. These negative decremental prices can be tuned to account for potential conflicts with other constraints or the prices of other units.

- The intent of these negative decremental prices is to have the optimisation engine avoid these actions as they would result in a high cost (the optimiser is trying to minimise cost). However these units can still be decremented in order to avoid violation of any operational security constraints (which have a higher violation cost).

Priority Dispatch – (2/2)

- Priority Dispatch generation is comprised of dispatchable units (e.g. peat, hydro, CHP) and non-dispatchable (but generally controllable) units (wind and solar). Dispatchable units must submit PNs and their priority dispatch status will apply to their PN'd quantities. Any availability above the PN'd quantity will not be treated as priority dispatch but in normal economic order. Non-dispatchable units may submit PNs however we will use our own forecast of availability to schedule these units to their full actual availability subject only to operational security constraints.

- We develop the schedule to ensure that sufficient 'room' is made available to accommodate priority dispatch generation (i.e. non priority dispatch units will have their output reduced or they may even be de-committed) and that sufficient System Services are scheduled to support system operation (such as the scheduling of sufficient inertia on the system to support the operation of the system during high wind conditions). Our objective is to minimise any operational security related constraint or curtailment of priority dispatch sources.

Outputs

The following sections describe the outputs of the scheduling and dispatch process:

- Indicative Operations Schedules (IOSs)
- Dispatch Instructions (DIs), Control Actions and Cross-Zonal Actions
- Data to Pricing and Settlement Systems

Indicative Operations Schedules (IOSs)

- The output of each scheduling run (LTS, RTC and RTD) is an IOS representing a plan of commitment / de-commitment decisions and MW levels for each unit given the inputs at the point when the schedule is initiated.

- Relevant IOSs will also indicate any proposed implementation of a Cross-Zonal Action (subject to an agreed approach to taking/facilitating such actions).

- The continuous nature of the scheduling process in accounting for the latest inputs means that the IOSs will be a good indication of expected commitment and running levels however they are always indicative until a dispatch instruction is issued or a control action taken by the TSOs.

- The TSOs publish IOSs.

Dispatch Instructions, Control Actions and Cross-Zonal Actions Overview Part – (1/4)

- Based on the IOS, and taking real-time system conditions into account (such as system frequency, voltage and thermal circuit loadings), dispatch instructions and other control actions are determined and issued by us to individual dispatchable and controllable units. Any required deviation from the IOS will be taken in line with a merit order of available actions (to increment/start-up units or decrement/shut-down units) taking into account real-time unit operating levels, unit response characteristics and operational security requirements.

- Each IOS is a MW schedule of unit production/consumption levels from which the following dispatch instructions / control actions are determined:
  - Synchronise – connect to the power system;
  - De-synchronise – disconnect from the power system;
  - MW Level – the active power MW level to which the unit should operate. All MW instructions are 'open' meaning that once achieved; the MW level should be maintained until a subsequent instruction is issued. Within this instruction type the TSO has the ability to define a time until which the instruction applies, known as the effective until time, however this is only relevant to settlement and not physical operation;
  - Wind farm / solar unit Active Power Control – MW active power control set-points;
  - Cross-Zonal Action – implementation of a change to an ICRP to implement a Cross-Zonal Action.

Dispatch Instructions, Control Actions and Cross-Zonal Actions Overview Part – (2/4)

- In addition to these instructions based on the IOS, other control actions on units and interconnectors can be taken:
- Instructions to provide System Services which can be explicit or implicit:
  - Explicit: an instruction to provide reactive power or operate in a specific mode (see 'Operating Mode' below) or
  - Implicit: an instruction implied from the MW dispatch instruction such as a unit being instructed to operate below its maximum output to provide operating reserve;
- Operating Mode – Pumped Storage and some CCGT units can operate in different modes. The scheduling process will be based on the mode of operation determined by the Participant via their TOD set selection however we may also instruct a mode change;
- Instructions to change fuel – some units are capable of operating on different fuels and may be instructed to switch fuel based on their own requirements, for the purposes of a test or in a fuel emergency situation;
- Maximisation instruction – an instruction to operate at a level in excess of declared availability;
- Emergency Instruction – an instruction that could require operation outside of normal declared capability.

Dispatch Instructions, Control Actions and Cross-Zonal Actions Overview Part – (3/4)

- We issue dispatch instructions and control actions over a range of timescales reflecting the technical characteristics of units. These instructions can be categorised as long notice (prior to Balancing Market Gate Closure) and short notice (after Balancing Market Gate Closure)

  i. Long notice actions: Instructions to synchronise can take a number of hours to implement and are issued in line with the notification time required by the unit to start-up which, for many thermal units, is ahead of Balancing Market Gate Closure. These longer notice instructions relate to managing operational security constraints such as deployment of sufficient capability to provide operating reserves and constraining on units to provide voltage support. They can also be taken to ensure sufficient headroom is made available, and System Services provided, to facilitate priority dispatch generation. On some units, the de-synchronisation process may take longer than one hour, i.e. the time from a unit being told to shut-down until it actually disconnects from the power system.

  ii. Short notice actions: Instructions associated with real-time balancing of supply and demand, optimisation of security constraints and priority dispatch levels ('MW' dispatch instructions and wind farm / solar unit active power control). These instructions are issued after Balancing Market gate closure in real-time taking into account the ramp rates of units that are already on. Units with short notification times can also be instructed to synchronise/de-synchronise in this timeframe. Delivery of System Services such as reactive power are also instructed in real-time taking into account the unit's control system response characteristics.

Dispatch Instructions, Control Actions and Cross-Zonal Actions Overview Part – (4/4)

- We may issue dispatch instructions at any time point in time and for any quantity so long as it respects the technical characteristics of units (other than for the maximisation and emergency type instructions listed above). So while dispatch instructions should align with the latest IOS, they do not have to exactly coincide with the IOS's scheduling interval or scheduled quantity. For example, an IOS with the following schedule for a unit 14:00 100 MW, 14:05 110 MW, 14:10 120 MW, could result in an actual dispatch instruction issued at 14:02 of 130 MW.
- The timing and magnitude of actual instructions that we issue will take into account the real-time conditions of the power system. For example we will delay or bring forward a dispatch decision for a unit to change output based on actual system frequency. If system frequency is low, indicating a negative imbalance, we may advance an instruction to increment a unit or delay the decrement of a unit.
- In the event of wind curtailment being required, we issue curtailment instructions to wind farms on a pro-rata basis in order of wind farm dispatch category.
- All units must follow the dispatch instructions that we issue. All controllable wind farms are controlled directly by us. No unit should synchronise, intentionally desynchronise or change output (other than for automatic frequency response) without a dispatch instruction from us.
- It is intended that solar units will be treated like wind units with respect to curtailment.

Data to Pricing and Settlement Systems – (1/2)

- The dispatch instructions issued and actions that we take result in the delivery of balancing energy and System Services. Data from the scheduling and dispatch process feeds the respective settlement systems so that Participants and System Service providers are settled appropriately. There are also charges related to the performance of units such as Other System Charges and Generator Performance Incentives (GPIs) and outputs of the process that relate to Capacity Market settlement.

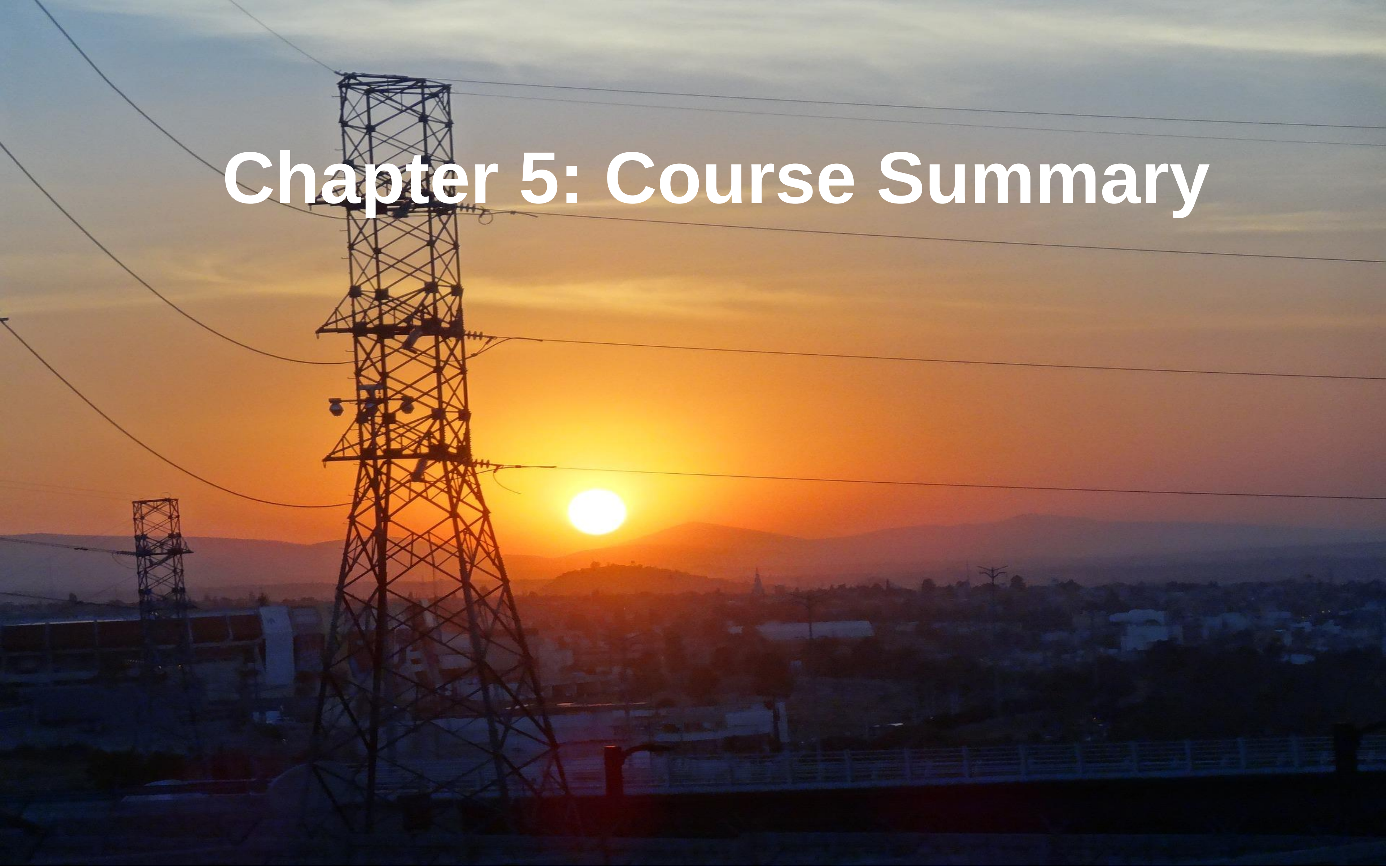
- The table below illustrates the range of scheduling and dispatch process outputs used in pricing and settlement systems. Note that there are additional data inputs to each system such as COD, TOD and market metering that are not included in this illustration.

Data to Pricing and Settlement Systems – (2/2)

Scheduling and Dispatch Process Data Item	Imbalance Pricing	Balancing / Capacity Market Settlement	System Services Settlement	Other System Charges & GPIs
Dispatch instructions	Y	Y	Y	Y
Cross-Zonal Actions	Y	Y	Y	
Real-Time Availabilities	Y	Y	Y	Y
System Operator Flags	Y			
Non-Marginal Flags	Y			
Short Term Reserve Quantity	Y			
Short Term Reserve Requirement	Y			
Quantity of Demand Control	Y			
System Services Flag		Y		
Operational metering (SCADA)			Y	Y

The Imbalance Price for each Imbalance Pricing Period (each 5 min period) is set by the marginal, unconstrained unit in that period. Whether or not a unit is constrained in each 5 minute period is identified within each RTD schedule. This identification process is an automated, rule based, process which is captured in our 'Methodology for System Operator and Non-Marginal Flagging'.

Chapter 5: Course Summary



Review of Learning Objectives

As a result of this training module, for the arrangements under the Capacity Market Code, you should now:

- Be aware of the objectives of the TSOs' scheduling and dispatch process ✓
- Appreciate the continuous, dynamic nature of this process ✓
- Understand why the TSOs may dispatch units away from their Physical Notifications ✓
- Know that all units must follow the dispatch instructions issued by the TSOs ✓