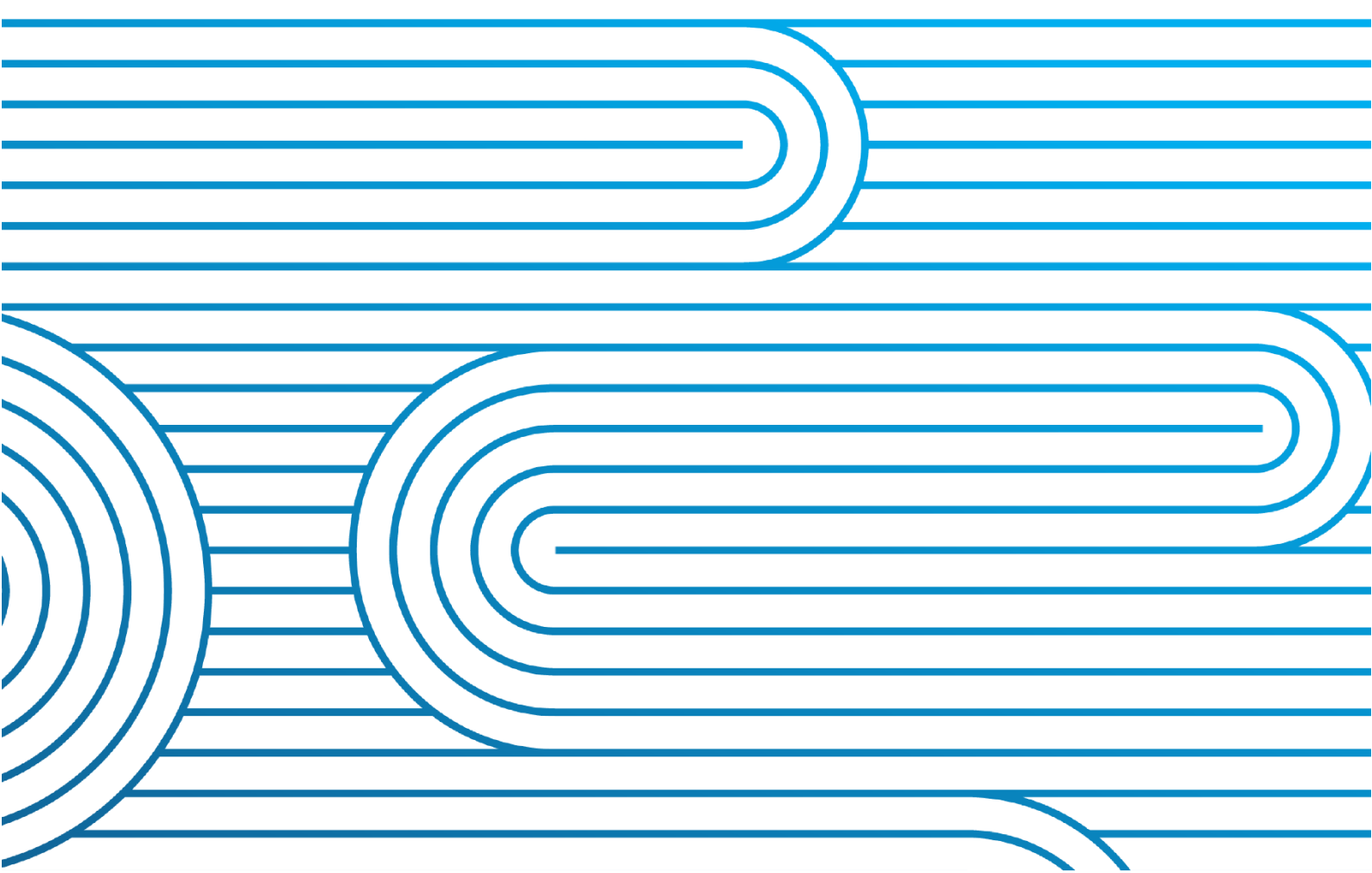


GL-OC-984 Dispatch Schedule Load Input guideline

Expected Profile of Demand Formulation

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|---------|-----------|---------|--------|---------------|------------|
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| | Position | Date |
|--------------|--|-----------|
| Prepared By: | Transpower as system operator | June 2022 |
| Approved By: | Phil Yao: SO Market Principal Specialist | June 2026 |

Related Documents

Electricity Industry Participation Code, Parts 8 and 13

Policy Statement

IMPORTANT

Disclaimer

This guideline is developed within the current regulatory framework and is accurate as at the published date. Subsequent changes to the Code or other regulations and policies may result in inaccuracies. Please contact Transpower to discuss current requirements.

This guideline does not relieve asset owners from identifying and meeting their obligations set out in the Code. Where there is conflict between this guideline and the Code, the Code takes precedence. Asset owners are strongly advised to seek expert advice to understand their full obligations under the Code.

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1 Introduction

1.1 Document Purpose and Scope

This document describes the methodology for preparing the Expected Profile of Demand as used in the **dispatch schedule**. The Expected Profile of Demand is the demand at each **Grid Exit Point (GXP)** that is expected to be required to be met by Dispatchable Resources (generation and Dispatchable Demand) at the end of the five-minute interval for which the **dispatch schedule** is solving. This profile forms one of the key inputs to the **dispatch schedule** which ultimately determines **dispatch instructions** and **dispatch prices**. Under the real time pricing market design **dispatch prices** are averaged on a time-weighted basis to form **trading period** prices.

1.2 Relevant Regulations and Policies

1.2.1 Policy Statement

This document is presented under the requirement of clause 84L of the **policy statement**.

The **policy statement** is a document incorporated into the **Code** by reference.¹ It describes (among other things):

- the **system operator's** use of the Scheduling, Pricing and Dispatch ('SPD') software for the formation of **dispatch instructions**;
- the inputs to the **dispatch schedule** and how the **system operator** makes adjustments to the schedule;
- the additional requirements the **system operator** observes in order to meet its obligations under the Scheduling and Dispatch subpart of Part 13 of the **Code**; and
- how the **system operator** uses its Discretion in dispatch.

1.2.2 Electricity Industry Participation Code ('the Code')

The requirements for the formation and quality of the **dispatch schedule**, and the provision of associated information are described in the **Code** at Part 13, Clauses 13.69A – 13.69D.

Under Schedule 8.3 of the **Code**, Technical Code C also requires **asset owners** (including **grid owners**) to provide the **system operator** with the relevant indications and measurements described in Appendix A of that Technical Code.

The details in this document do not supersede, alter or remove any obligations as outlined under the **Code** or the **policy statement**.

1.2.3 Other documentation published by the system operator

Readers may wish to read this document in conjunction with the following other published guidelines and procedures:

- [GL-OC-209 SPD Schedule Inputs](#)
- [GL-DP-983 Post Schedule Checks](#)

¹ Refer clause 8.10 of the **Code**.

1.3 Notes on terminology

1.3.1 Similar terms

The concepts described in this guideline exist simultaneously in multiple 'domains', such as engineering, economics, power system operation and legislation. Different domains develop independently and thus naturally assign different names for similar concepts; for instance, the consumption of electricity measured as a flow of energy out of the **grid** is known interchangeably as 'Load' and '**demand**'. As applied to the process of preparing the inputs to the **dispatch schedule**, this concept of load is allocated various labels depending on its state in the overall process and the context in which it is described. Where possible, the terminology is defined at first use and summarized in the Glossary provided at Appendix A, together with equivalent terms from different domains.

1.3.2 Correspondence with the Code

Where terms have been defined in the **Code**, these are presented in bold text. These include terms which are defined in the **policy statement**.

1.3.3 "Net" vs "Gross"

In its Schedules, the market system attempts to balance Required Load (the "target" for the amount of energy to schedule) with Dispatchable Resources. This means Required Load must be *gross* of any generation located behind the **GXP** that is offered into the market (offered Embedded Generation).

The **grid owner** is required to provide the system operator with a demand measurement that is the *net* volume of electricity flowing out of the grid at each **GXP**. Therefore the **system operator** must adjust this value to be the *gross* load by adding any Embedded Generation at each **GXP**. The instantaneous measurement of offered Embedded Generation is provided separately by the **generators**.

Conversely, Dispatchable Demand (DD) provides a Dispatchable Resource that reduces the load target. Dispatchable Demand will be dispatched according to the bid information supplied by the Purchaser – if there is an adequate volume of appropriately priced generation available, then Dispatchable Demand will be dispatched. Because Dispatchable Demand is optimisable in this way, it is not treated as Required Load, and is subtracted from the gross load input.

2 Overview

2.1 Dispatch Schedule

In order to schedule generation and other Dispatchable Resources in real time the **system operator** produces a **dispatch schedule**. The **dispatch schedule** forms the basis of **dispatch instructions** that are issued to Dispatchable Resources. A key determinant of the dispatch solution is the Expected Profile of Demand for the schedule timeframe. An overview of this process, with the associated obligations in the **Code** and **policy statement**, is presented as Figure 1.

2.2 Expected Profile of Demand calculation

2.2.1 Application timing

The Expected Profile of Demand is the (non-DD) load used in the **dispatch schedule**. The Expected Profile of Demand is the **system operator's** estimate of what the non-DD load will be at each **GXP**, at the end of the Market Interval for which the schedule is produced. As an input to SPD it is known as Required Load.

Dispatch schedules are typically completed approximately 30 seconds before the Market Interval to which it applies, but system co-ordinators may also solve a manual **dispatch schedule** and redispach the power system more regularly. As an example, for the 10:30-10:35 Market Interval, an automated Dispatch Schedule will commence at 10:29:00 and complete around 30s later, and there may be manual schedules solving for this market interval anytime until 10:34.

2.2.2 Calculation – high level

The **dispatch schedule** Required Load is calculated on the basis of a measurement of the load at the time the schedule is initiated ("Current GXP Load"), which is Scaled by a quantity consisting of the expected change in load within the Market Interval ("Pre-Solve Deviation, PSD"), and the estimated error between measured electricity generation and load.

$$\text{Required Load (RTD)} = \text{Current GXP Load} + \text{PSD(GXP)} + \text{Load Error} \quad (1)$$

Figure 2 shows the sequence of processes used to generate the Expected Profile of Demand.

Where practicable, the Current GXP Load is sourced from the Grid Owner's revenue meters, sometimes known as "ION" meters. Several back-up data sources for Current GXP Load may be used where revenue meter data is not available. This source validation and selection is described in detail in Section 3.

The PSD is the quantity of expected change in load over the Market Interval, at the Island level. To allocate the Island-level quantity across the island's GXPs, a Load Participation Factor is used, derived from the recent historical measured load at each **GXP** (or from back-up sources where necessary). The application of the Scaling quantity is contingent on a number of conditions at each **GXP**. This is further detailed in Section 4.

Once the estimated Required Load has been determined and SPD has solved, any Energy Shortfalls are identified and correlated with outages of grid equipment. Where there is a correlation, or where the application of the PSD has caused an Energy Shortfall, the Required Load is adjusted to remove the Shortfall. This is described further in Section 5.

This calculation must be robust to changes in system modelling (both network and market models), and planned and unplanned outages affecting site-specific communications and system failures. Details of how the load input subsystem responds to these system events is provided in Section 6.



2.2.3 Non-conforming GXPs

The Required Load at **non-conforming GXPs** is the Current GXP Load; no Scaling is applied. If a **non-conforming GXP** is subject to a **grid** outage, any Shortfall is adjusted as per the treatment described in Section 5.

2.2.4 RTD Pricing Optimisation (“RTDP”) during Demand Management

When the **system operator** instructs **demand management** (“load shedding”) under clause 6 of Technical Code B of Schedule 8.3 of the **Code**, to maintain a wholesale price reflective of the load that was shed, a separate optimisation is run within the **dispatch schedule** from which **dispatch prices** and Shortfall quantities are published. This optimisation runs with a load input which is adjusted for the Load Shed Quantity instructed at each GXP.

$$\text{Required Load (RTD-P)} = \text{Current GXP Load} + \text{Load Shed Quantity (GXP)} \quad (2)$$

The Load Shed Quantity does not incorporate Scaling as described above. Further detail on the RTD-P optimisation and the derivation of the Load Shed Quantity is provided in Schedule 13.3AA of the **Code**.

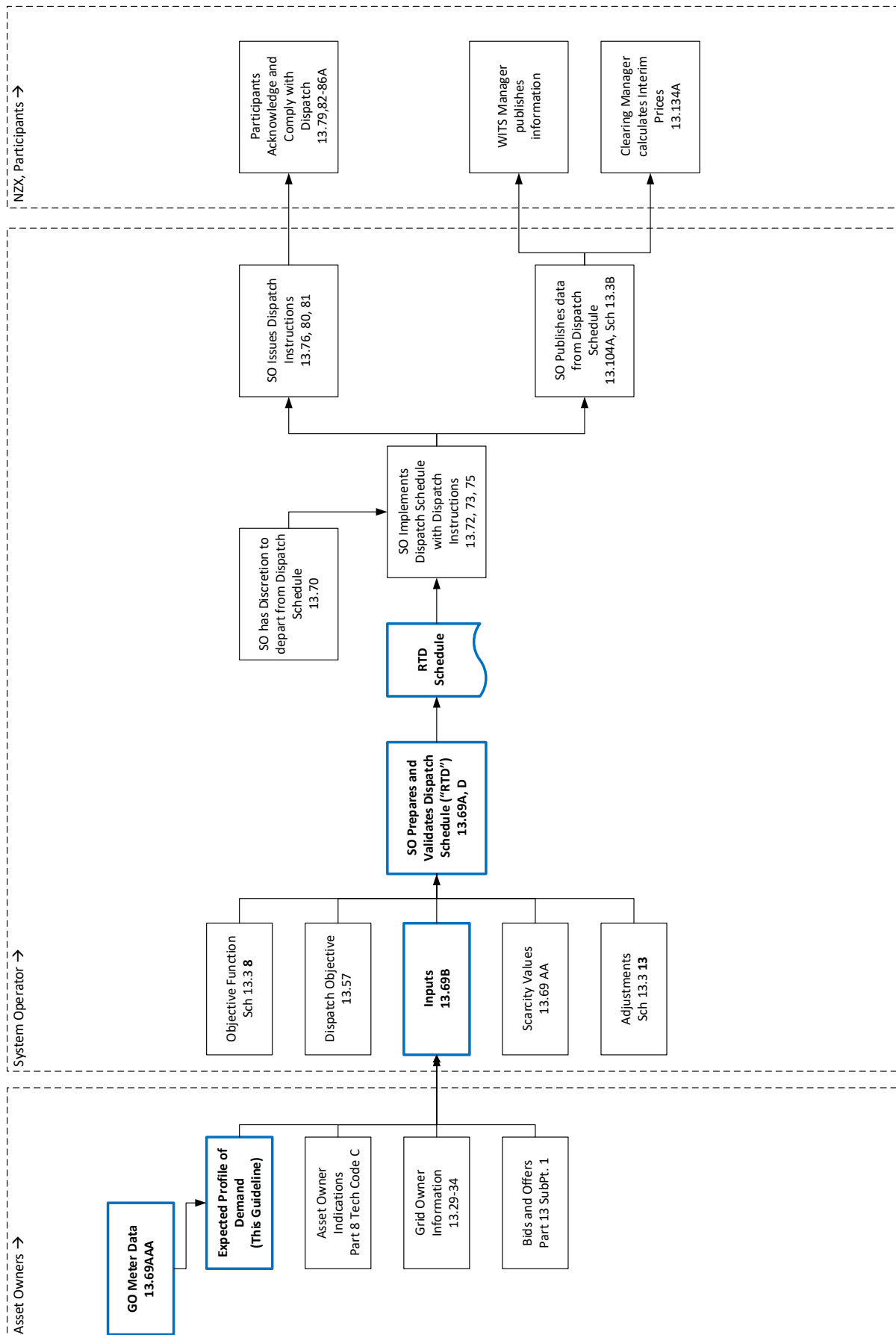


Figure 1 – Dispatch process overview, highlighting the scope of this Guideline (blue outlined artifacts).

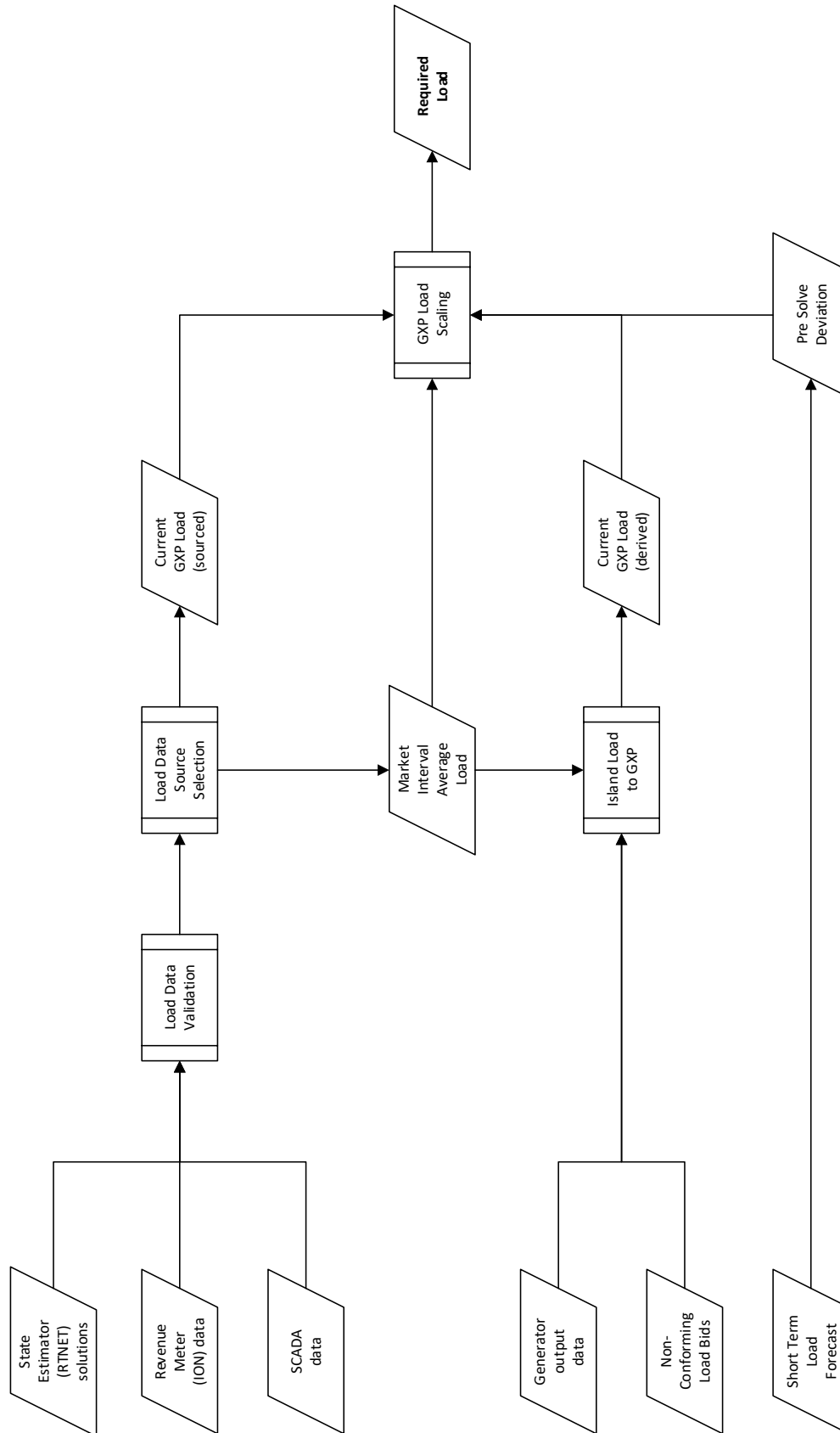


Figure 2 – Simplified process schematic for formulating Required Load in the dispatch schedule.

3 Current GXP Load Source Measurement, Validation and Selection

3.1 Current GXP Load Sources

The basis for the calculation of Expected Profile of Demand at each **GXP** is the instantaneous measurement of Current GXP Load. There are two semi-independent primary measurement sources employed by the **system operator**, both supplied by **Transpower** as the **grid owner** – “ION²” revenue meters and field measurements processed with the national SCADA system (“SCADA”). In addition, there are two derived measurements of instantaneous GXP load, the State Estimator (“SE”) and Island Load Disaggregation.

3.1.1 Revenue Meter Measurements

Under clause 13.69AAA of the **Code**, the **grid owner** is required to supply real time net **demand** values for each of its **GXPs** to the **system operator**, from its **grid** revenue meters (where practicable). The **grid owner** maintains revenue metering to fulfil their obligations to supply **GXP volume information** to the **reconciliation manager**.³ In addition to providing half-hourly volumes, the revenue meters are capable of making instantaneous measurements which are the basis of the **GXP** Load measurement. The required accuracy of the revenue meters is +/- 0.75%.⁴

Revenue meters are typically located on each feeder at a **substation**. The summation of each of the meters’ measurements constitute the (net) flow at the **GXP** and is calculated with the same regularity as the individual meter measurements.

The revenue meters have an intrinsic quality indication which is based on whether communications to each of the meters constituting the GXP Load summation are good. If communications to an individual meter fails, the reported quality is bad. This impacts whether the market system selects the revenue meter as the chosen data source for a given **GXP** at that point in time.

The revenue meter GXP Load summation and quality is sampled by the SCADA system on a **4** second frequency, with a 0.001 MW dead band; if the load measurement has not changed by **±0.001** MW between measurements, no new data is provided to the SCADA system.

3.1.2 SCADA Field Measurements

The **grid owner** is also required to provide indications and measurements to the **system operator**, including **grid interface** MW, to an accuracy of **±2%**.⁵

Grid interface MW values are calculated as the multiplication of measured currents of each feeder circuit and measured bus voltages. If communication to either of the measurement devices is lost, the SCADA system derives a bad quality indication. Measurements are sampled on a 4-second basis with associated dead bands for current and voltage.

3.1.3 State Estimator

Monitoring and controlling the power system requires continuous measurement of thousands of different variables around the network such as bus voltage, branch flows, transformer taps and circuit breaker status. Where direct measurements of individual values are unavailable or compromised due to equipment outages or

² “ION” refers to the brand name of the revenue meter employed by Transpower as the grid owner.

³ Refer clause 15.9 of the Code.

⁴ Refer Schedule 10.1 of Part 10 of the Code

⁵ Refer clause 6 and Appendix A of Technical Code C of Schedule 8.3 of Part 8 of the Code.

failures, or where there is disagreement among a subset of the measured values the **system operator** relies on its Energy Management System's (EMS/SCADA) State Estimator application – known as RTNET.

RTNET runs an optimisation algorithm to find the best representative state of the **grid** given the available measurements and consistent with known parameters of the grid such as branch impedance and equipment connectivity. The result is a powerflow-like solution which is used as the basis of further security assessments (e.g. Contingency Analysis) to ensure the **grid** remains secure.

RTNET can be used to back-fill missing measured data in **system operator** systems – for example **generating unit** injections or load values – although these values may not always correspond exactly in some locations due to network boundary modelling. Where there is a systemic discrepancy between actual measured loads and RTNET estimated values, the State Estimator is not selected for use as a valid load measurement source.

3.1.4 Island Load Disaggregation

In the absence of reliable real time load measurements, the **GXP** loads can be estimated based on current generation output measurements. This is the method that was used to calculate **GXP** level load for the dispatch schedule prior to RTP.

Generators are required to provide real time indications of their output to the **system operator**.⁶ Since at any point the system generation and load should be approximately equal, we can infer that the sum of generator output is equal to the load (plus losses) on the system. Therefore, having made an estimate of system losses, we know at an Island level the total Island Load. This Island Load can be apportioned to each **GXP** with Load Participation Factors, which are calculated as the average measured or estimated load from the last 5 minutes.

3.2 Conversion to Gross Load

As described in section 1.3.3 the Market System aims to schedule offered generation to balance the Required Load. Where real time indications are received as net load values (revenue meter and SCADA instantaneous measurements) these must be adjusted for offered embedded generation and Dispatchable Demand⁷ consumption behind the **GXP**. This calculation is performed in the SCADA system. The quality of the gross load is derived as the least quality of the constituent parts of the calculation, so if any of the net load value, the offered embedded generation value, or the Dispatchable Demand value are bad quality, the quality of the gross load calculation is an inherited bad quality, **and the source is discounted from further processing**.

$$\text{Gross Load (GXP)} = \text{Net Load (GXP)} + \sum \text{Offered Embedded Generation} - \sum \text{Dispatchable Demand} \quad (3)$$

3.3 Provision to the Market System

Each of the primary data sources and State Estimator results are provided to the market system through the EMS/SCADA system. EMS/SCADA is used to collect all real time load measurements on the power system and is maintained as a critical component of the operation of the national grid. It is a dual-redundant network of communications devices and software platforms for which unplanned outages are rare and planned maintenance outages are typically brief. Figure 3 shows a schematic of the components of the EMS/SCADA communications network to the Market System.

⁶ Refer clause 6 and Appendix A of Technical Code C of Schedule 8.3 of Part 8 of the **Code**, **and/or the Connected Asset Commissioning, Testing and Information Standard (CACTIS)**.

⁷ For more information, refer to the Transpower website: <https://www.transpower.co.nz/system-operator/electricity-market/dispatch-capable-load-station-setup>

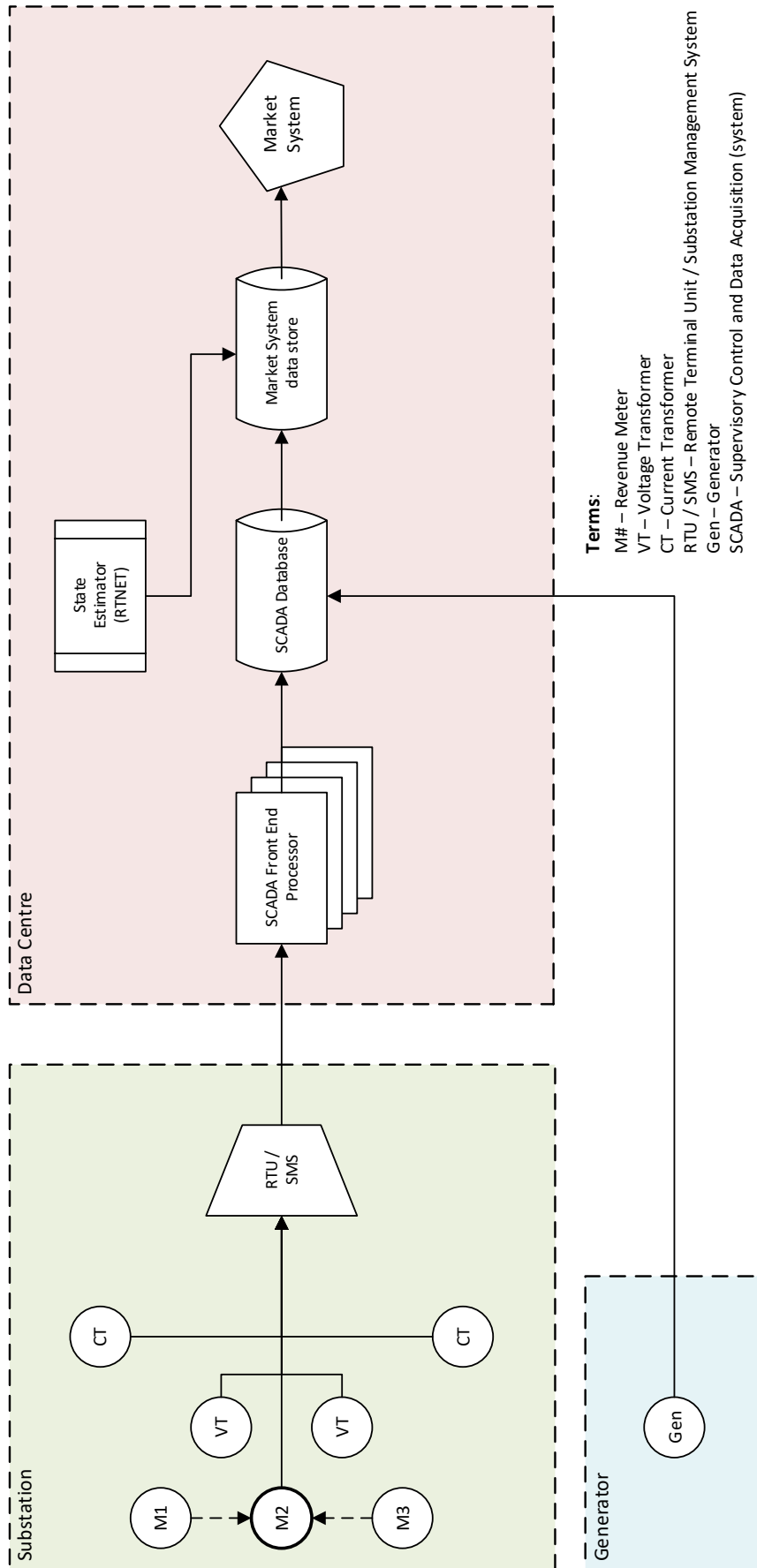


Figure 3 – Field measurement data flows into SCADA and the Market System.



3.4 Load Measurement Validation

The revenue meter system, the EMS/SCADA system and the Market System all employ logical validation checks to prevent bad quality data being used in downstream processing. The validation checks are described in Table 1. The relevant validation checks are applied when each measurement is sampled in the EMS/SCADA domain, and when the Market System runs its validation and selection procedure on receipt of the raw data supplied by EMS/SCADA.

Table 1 – Summary of GXP Load measurement validation in each technical domain

| Domain | Check | Criteria | Result |
|------------------|---|--|--|
| Revenue Metering | Live communications to each meter at GXP | Communications lost to one or more meters for more than 30s | Aggregate Quality Bad |
| EMS/SCADA | Revenue meter aggregate quality | Quality is Bad | Quality Suspect |
| | Live communications to each field measurement device (including revenue meters) | Communications lost within 4s sample time | Quality Suspect |
| | Limit check – SCADA | Measurement exceeds reasonable physical range | Quality Suspect |
| | Limit check – revenue meter | Measurement exceeds configured operational limit | Quality Suspect |
| Market System | Dead-band | Measurement has changed by at least a minimum quantity, or its quality has changed, or sufficient time has elapsed since last measurement received | Measurement available to market system for processing |
| | Not from the past | The measurement is current in time | Measurement available to market system for processing |
| | Received quality | Measurement quality Good or Replaced | Measurement acceptable for further checks |
| | | Measurement quality Suspect or Garbage | Measurement rejected |
| | Minimum number of acceptable measurements | A sufficient (configurable) number of acceptable measurements have been received | Latest measurement acceptable for further checks |
| | Trip check | Measurement drops to zero (with allowance for noise) | If Tripped then Age and Limit check disabled for that GXP, measurement available for selection |
| | Age check | Measurement does not change within a configurable 'Time to Live (TTL)' | If last change exceeds TTL then measurement not available for selection |
| | Limit check | Measurement exceeds configured operational limit | Measurement not available for selection |

3.5 Current GXP Load Source Selection

Having received the instantaneous measurements and State Estimator solution, and applied the acceptance rules for each, the Market System then determines which value to use as the Current GXP Load (or whether to estimate the load using Island Load Disaggregation). For each GXP a hierarchy of source preference is specified, with the typical selection being:

1. Revenue Meter
2. SCADA
3. State Estimator.

The Market System reviews whether an acceptable measurement exists for each source in turn, and uses the first good source in the hierarchy. If none of the configured sources are acceptable, the value for Current GXP Load is calculated by Island load Disaggregation.

3.6 Co-ordinator Override

When the system co-ordinators expect that none of the automated processing described above will result in a correct value for the Current GXP Load, the co-ordinators may apply an override value that will substitute any automatically calculated value. There are **three** cases where this may occur:

- overrides may be used to manage a Tiwai Point **reduction line change operation** in order to maintain an accurate dispatch solution
- for post-event restoration activities or system failures where measurement data quality is compromised, and estimation methods are not providing adequate solutions
- **a temporary adjustment to reflect real-world powerflows where the modelling system may not provide a sufficiently accurate load value.**

4 Required Load Calculation

4.1 5-minute Average Load Calculation

The distribution of island-level load quantities to **GXP** is governed by the 5-minute average load for each **GXP**, also known as Current Bus Load Participation Factor (BLPF) or Current BLPF. In normal operation, where **GXP** load measurements are available, the 5-minute average load is the time-weighted average of selected **GXP** load measurements across the 5-minute Market Interval. Where no acceptable load measurements are available within a given Market Interval, the previous 5-minute average load quantity is assumed to persist for a configurable duration, usually 30 minutes.

Beyond this point, an adjusted Trading Period BLPF is used. The Period BLPF is the 30-minute average load quantity for each **GXP** from the same trading period the previous week. This quantity is scaled according to the sum of **GXP** current measured loads across the load forecast region to which the **GXP** belongs, compared to the load for the same **GXPs** within forecast region from the previous week.

$$\text{Adjusted Period BLPF (GXP)} = \text{Last Week Period BLPF (GXP)} \times \frac{\text{Current Area Load}}{\text{Last Week Area Load}} \quad (4)$$

4.2 Application of GXP Load Scaling

Having sourced or calculated the Current GXP Load, the Required Load for each **GXP** can be calculated according to equation (1) by adding a Scaling value. The Scaling value is derived from disaggregating the PSD, an estimate of how much Island load is expected to increase or decrease in 5 minutes' time, plus the Island Load Error, to each **GXP** according to a set of disaggregation rules. Scaling will not be applied to a GXP where either:

- the **GXP** is a **non-conforming GXP** (see section 2.2.3);
- the Current GXP Load has been overridden (see section 3.6);
- the 5-minute average load for the **GXP** is negative (unoffered embedded generation has exceeded the load at the **GXP**); or
- the GXP is subject to an Applied Load Limit.⁸

Where the Scaling value is applied, it is calculated according to the following equation:

$$\text{Scaling value (GXP)} = \text{Current BLPF} \times (\text{Pre-Solve Deviation} + \text{Island Load Error}) \quad (5)$$

4.3 Pre-Solve Deviation

The Pre-Solve Deviation (PSD) is the expected change to the current (Island) load for the next 5-minute interval. Every six to ten seconds the market system automatically calculates the expected change based on the change in the short term load forecast from the current interval to the next.

System co-ordinators can override automatically calculated PSD with manual values. This may be necessary where system conditions are not able to be modelled accurately in the market system, for example during generator warm-up prior to ramping.

⁸ Refer to the Energy Scarcity Pricing Mechanism (Schedule 13.3AA of the Code) for more detail.

4.4 Island Load Error

Electricity **supply** and **demand** must always be in balance (as close as practical to maintain system frequency at 50 Hz). Therefore, at any instant the aggregated generation output across a given island is almost equal to the island load, plus **losses** across the transmission network. Given a reasonable **loss** estimate⁹, and assuming greater accuracy in generator measurements than load measurements¹⁰ we can therefore compare the aggregate island load measurements with the aggregate **generation** output and derive a difference between the two quantities. This is termed the Island Load Error:

$$\text{Island Load Error} = \sum \text{generation output} - (\sum \text{GXP load} + \text{Losses}) \quad (6)$$

The Island Load Error for each **dispatch schedule** is calculated and allocated to each eligible **GXP**, as described in section 4.4, according to equation (5).

⁹ The Dispatch Schedule uses the losses calculated from the previous SPD solve for its initial loss estimate, which is then refined within each case.

¹⁰ This has been assumed historically, and given there are fewer measurement points for generation, there is less opportunity for measurement error.

5 Shortfall Quantity Adjustment

5.1 Circumstances Requiring Load Adjustment

The Required Load is inherently an estimate; the magnitude of the load at each **GXP** is derived considering the expected change in load at an island level, which is then allocated according to the proportion of load consumed at each **GXP** in the previous Market Interval. The Required Load calculated in this way could therefore exceed the available **supply** capacity¹¹ for each **GXP**. We would not normally expect load at a **GXP** to exceed the **grid's** ability to supply it, therefore it would be unreasonable to model this in the **dispatch schedule**.

Similarly, the **system operator** continuously forecasts the **supply** capacity at each **GXP** as part of the scheduling process. To do this, the system operator models outage information supplied to it by the **grid owner**. The **grid owner** provides:

- the **grid** equipment that is affected by a physical outage;
- the planned start and end times of the physical outage, to the half-hour;
- the actual start and end times of the physical outage corresponding to the commencement of the initial switching sequence, and the termination of the final switching sequence;
- whether the outage is continuous or daily over several days; and
- the state of the equipment during the physical outage, specifically, whether it is removed from service (RS), or open-ended (OPE).

Notably, SPD uses a half-hourly offered grid in the process which determines the network topology for its optimisation. The **dispatch schedule** uses Current GXP Load inputs to calculate a powerflow for generation scheduling. One possible consequence of the interaction between a half-hourly offered **grid** model and real-time load measurements is SPD can be left with an Infeasibility – it may **schedule** a quantity of Required Load at a location at a time when the modelled **supply** capacity is insufficient to meet it, despite the **grid** being physically able to supply the current Load (i.e. the physical outage hasn't started at the modelled start time).

Both these circumstances would lead to spurious Energy Shortfalls and scarcity prices, if not adjusted prior to real time **dispatch**.

5.2 Determining Required Adjustments

5.2.1 Discovering Energy Shortfall

To determine whether **supply** capacity has been exceeded in a Schedule, we need to compare the Required Load with the modelled capacity. In practice, given **supply** capacity can be dynamic, this comparison is performed within SPD itself. If SPD solves with an Energy Shortfall, and the Shortfall is a result of the circumstances described in section 5.1, the load input must be adjusted and the Schedule re-solved.

5.2.2 Assessing adjustment quantity

An Energy Shortfall may exist for four reasons:

1. There is a genuine Shortfall at a **GXP**;
2. A Current GXP Load is derived using the Island Load Disaggregation methodology and the result is in excess of GXP **supply** capacity;
3. The Scaling quantity added to the Current GXP load exceeds the **supply** capacity at the **GXP**;
4. The **GXP** is affected by a modelled **grid** outage which constrains its **supply** capacity.

¹¹ The combination of generation and transmission resources needed to delivery the Required Load.

In order to determine the quantity of load (if any) to reallocate to mitigate a Shortfall, SPD first identifies whether any grid outages are modelled which affect **GXP supply** capacity. This is achieved by passing SPD a model of related Connection Assets for each **GXP**. If an outage exists which models any of the connection assets as unavailable¹², then SPD nominates the entire Shortfall quantity at that **GXP** for adjustment.

If the Current GXP Load has been derived using the Island Load Disaggregation methodology (ie no direct measurement of Current GXP Load is available), the entire Shortfall quantity is nominated for adjustment, on the basis that the estimated load is too uncertain to constitute a genuine Shortfall and the associated pricing implications.

If a **GXP** is not affected by an outage of a relevant connection asset, SPD considers the Shortfall quantity compared to the Scaling component of the GXP Required Load. SPD then nominates the lesser of the two for adjustment. If the GXP Required Load is in excess of its supply capacity even with the entire Scaling components removed, then a genuine Shortfall exists.

On occasion the Current GXP Load may temporarily exceed the modelled **supply** capacity. Provided the modelling is correct, it is reasonable to proceed with the resultant scarcity price, as this price is reflective of the inability to supply the Load within the offered **asset** capability. In this situation the **system operator** may initiate emergency procedures to prevent damage to **assets**.¹³ If **demand** management is instructed at a **GXP**, then uncleared Load will be scheduled at the **GXP** and this will be used to derive **dispatch prices**.

5.2.3 Adjusting nominated adjustment quantities

Having discovered and assessed the Energy Shortfall at each **GXP**, SPD will make adjustments to the Load input to reallocate the nominated Shortfall quantities. Where possible, the total island load quantity must be preserved in order to maintain the quality of the overall **dispatch** solution (conversely, simply removing the scheduled energy shortfall would leave generation under-dispatched to meet the actual load on the system).

The nominated Shortfall quantities are reassigned to other nodes on the grid according to a modelled map. The other nodes are known as Load Transfer PNodes. Each **GXP** has one and only one Load Transfer PNode, and each Load Transfer PNode has a Load Transfer PNode of its own. The mapping is constructed according to the principles of nominating the electrically nearest live node, accounting for locational congestion where possible. For each **GXP**, applying these principles forms a 'chain' or potential nodes where the nominated load may be allocated, which are in sequence:

1. The high-voltage side of a supply transformer;
2. Another node within the same station;
3. A 'regional reference node', or node which represents a notional supply locus for the region;
4. A series of core-grid nodes that predominately supply the regional reference nodes; and
5. The island reference node.

SPD identifies the best acceptable node in this sequence, being a live node that is not itself supply constrained. SPD then transfers the nominated Shortfall quantity at a **GXP** to the selected node, plus a small margin of error, to the identified nodes. SPD then solves again, and the Schedule workflow finalises the results in the usual way.

5.2.4 Proxy pricing

When a GXP is Disconnected or Dead with load, SPD is unable to calculate the value of electricity at that location (there is no connected offered generation in its model). Instead a price must be assigned. When a GXP is **Disconnected** the price of electricity at the GXP is determined from the electrically nearest live node. This makes

¹² Either removed from service or open-ended.

¹³ Refer to Policy Statement clauses 57-84.



use of Load Transfer PNode methodology described in section 5.2.3. When a Proxy Price is required, the price will be derived from the Load Transfer PNode determined under this methodology.

5.2.5 Error handling

If a suitable Load Transfer PNode cannot be found, SPD must “fail gracefully” to allow co-ordinators to diagnose and correct the problem with the input information. In extreme cases, a Dispatch Schedule may be dispatched without an appropriate shortfall adjustment. Where SPD has discovered a spurious Shortfall that it cannot adjust, it will remove the Shortfall quantity and if the PNode is Dead or Disconnected, assign a price of \$0.00.

6 System Maintenance and Abnormal Conditions

6.1 Changes to network / market model

From time-to-time **GXPs** are added and removed from the **grid**, and network configurations can change, resulting in changes to the measurement equipment and calculation. These changes are typically modelled in the system during business hours, tested and exported with an effective date and time. These changes do not typically have significant impact on load measurement.

6.2 Site-specific communications outages

The Current GXP Load measurement system is designed to be robust to planned and unplanned outages of measurement devices, communications links and front-end data management systems. The market system employs logical data validation rules designed to exclude (to the extent possible) measurement errors. Communications outages can happen at any point along the Load data handling sequence and each system maintains methods for detecting communications network dropouts. Where either of these conditions are met, the market system validation detects the data as Suspect, and automatically attempts to use the next best data source.

6.3 Market system outage and Stand-Alone Dispatch

System operations must continue in the event of a market system outage. Our backup electronic dispatch mechanism is Stand-Alone Dispatch (SAD). SAD is a simple platform for calculating a generation schedule for electronic dispatch; apart from electronic dispatch, there is deliberately no other interface to other systems. Current GXP Load measurement is not used in SAD; instead, an approximate Island Load Disaggregation is used as the basis for calculating generation dispatch. While on SAD, the system operator will not publish dispatch prices.

6.4 Full SCADA system outage

Full SCADA outages are very rare and can cause significant impacts to system operation over and above calculating a dispatch solution. During a SCADA outage we expect to not have access to any Load measurement data and State Estimator data could be significantly degraded. The system operator maintains the capability to continue to generate Dispatch Schedules using Island Load Disaggregation and estimating full Island load based on previously dispatched generation quantities and recent historical load measurements.



Appendix A – Definitions of Key Terms

| Term | Definition |
|---|--|
| Applied Load Limit | Where an instruction to disconnect demand has been issued, the Applied Load Limit is the limit of load to be taken at a GXP which is derived from the nature, quantity and location of the instruction. |
| Connection Asset | In the context of dispatch, an asset forming part of the grid, an outage of which is nominated to affect supply capacity at a GXP |
| Current GXP Load | The (measured or derived) load at a given GXP at the present time, particularly at the time a dispatch schedule is initiated. |
| Dead (with Load) | A GXP which is modelled as disconnected from any offered generation, but which has Load. |
| Disconnected | In this context, a GXP is Disconnected when it has no Load or modelled connected offered generation. |
| Discretion | Related to dispatching the power system, Discretion is the right of the system operator to dispatch a resource out of economic merit as determined by the solution to the objective function, for the purposes of meeting the dispatch objective. |
| Dispatchable Demand (DD) | Demand that is made available for reduction on instruction from the system operator as part of the dispatch process. |
| Dispatchable Resource | In the context of this document, an offered quantity of energy (either from generation or Dispatchable Demand) or instantaneous reserve (either from partly loaded spinning reserve, tail water depressed reserve or interruptible load). |
| Embedded Generation | A quantity of energy supplied by an embedded generating station, which may be offered into the market for optimisation. |
| Energy Management System (EMS/SCADA) | The suite of applications used by the system operator to monitor and control the grid. |
| Energy Shortfall | The result of the Required Load exceeding the available supply capacity at a GXP. |
| Expected Profile of Demand | The demand quantities at each GXP input to the dispatch schedule. |
| Infeasibility | The outcome of SPD being unable to solve normally without breaking one of its mathematical constraints, for which a constraint violation penalty value is assigned. |
| Island Load Disaggregation | The calculation used natively by SPD to estimate Current GXP Load, where real time GXP Load measurements are unavailable. It uses a methodology of estimating Island Load from the sum of current generation measurements, subtracting losses, and disaggregating the result to each GXP passed on recent past real time measurements. |
| Island Load Error | The difference between the Island Load calculated from the sum of measured generation less losses, and the sum of measured GXP loads (including estimates). |
| Load | The flow of electrical energy out of the grid, measured in (mega)Watts [MW]. In the context of this document, synonymous with demand. See also Required Load |
| (Bus) Load Participation Factor (BLPF) | The fraction of load at a GXP compared with the total load for a particular Load Area or Island. In the Required Load context, this is derived principally from Current GXP load measurements for the previous Market Interval. |
| (Instructed) Load Shed Quantity | The quantity of load that is estimated to have been shed at a GXP following issuance of an instruction to disconnect demand under Technical Code B of Schedule 8.3 of the Code. |
| Load Transfer PNode | The modelled location on the network to which any Energy Shortfall will be transferred, in the event that the Shortfall is caused by a modelled transmission outage. |



| Term | Definition |
|--|---|
| Market Interval | Periods of 5 minutes duration beginning at hh:m0 and hh:m5, for which the dispatch schedule solves. |
| Market System | The collection of software applications which together produce schedules of prices and quantities, and provide for issuing dispatch instructions |
| Objective Function | The function which is solved in order to meet the dispatch objective. Described mathematically at clause 8 of Schedule 13.3 of the Code. |
| Optimisation | The act of a solver (usually SPD) working to solve the Objective Function. |
| Participant | In this document the term participant means electricity industry participants who receive dispatch instructions. The Code, clause 13.72, stipulates that dispatch instructions are to be issued to generators, ancillary service agents and dispatch capable load purchasers. |
| Pre-Solve Deviation (PSD) | The expected change to the current (Island) load for the next Market Interval |
| Required Load | The Load value at each GXP for which a schedule completes its Optimisation. |
| (Instantaneous) Reserve Shortfall | The result of the required Fast or Sustained Instantaneous Reserve (as the case may be) exceeding the available reserve capacity in an Island. |
| Scaling | The adjustment added to each Current GXP Load reflecting the expected change in load in the Market Interval. |
| Schedule | An instance of an Optimisation solution (“study”, “solve”) for one or more market intervals or trading periods, consisting of schedule inputs and schedule contents (results). |
| Scheduling, Pricing and Dispatch [software] (“SPD”) | The software the system operator uses to solve the Objective Function. |
| Stand-Alone Dispatch (SAD) | A software application employing a stand-alone version of SPD which allows the system operator to calculate economic dispatch when the Market System is unavailable. |
| State Estimator | A calculation engine which uses available power system measurements to estimate data points which are unavailable. The State Estimator used by the system operator is the RTNET application, part of the EMS/SCADA suite. |
| Supervisory Control and Data Acquisition (SCADA) | The system by which physical measurement of the power system are recorded and processed, and remote controls are issued. |