Real Time Pricing Report (TAS060)

Transpower Stakeholder Requirements and ROM Review to Implement a Dispatch-Based RTP

February 2017

Keeping the energy flowing




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Transpower New Zealand Limited The National Grid

Version	Date	Change
0.1	3/Oct/2016	Initial draft
1.0	27/Feb/2017	Final

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Abbreviations

The abbreviations used in this document are provided below.

Authority	Electricity Authority
BLPF	Bus Load Participation Factor
CAS	Constraint Adjustment Schedule
Code	Electricity Industry Participation Code
CE	Contingent Event
CVP	Constraint Violation Penalty
DD	Dispatchable Demand
DSBF	Demand Side Bidding and Forecasting
DTS	Dispatch Training Simulator
DW	Data Warehouse
EDB	Electricity Distribution Company
EDE	Eterra-archive Data Extraction
EDF	Electronic Dispatch Facility
ESB	Enterprise Services Bus
ETS	E-Terra Source
FP	Final Pricing
FTR	Financial Transmission Rights
GIP	Grid Injection Point
GO	Grid Owner
GSS	Grid Security Services
GXP	Grid Exit Point
HSWPS	High Spring Washer Pricing Situation
HVDC	High Voltage Direct Current inter-island link and control systems
ICCP	Inter-control Centre Communications Protocol
IG	Intermittent Generation
IPLC	Integrated Project Life Cycle
IR	Instantaneous Reserve
LF	Load Forecast
MDB	Market Database

MOI	Market Operator Interface
MS	Market System
NCC	National Coordination Centre
NCL	Non-Conforming Load
NRS	Non Response Schedule
PEC	Pricing Error Claim
PEC	Pricing Error Claim
PPO	Principal Performance Obligation
PRS	Price Response Schedule
PSC	Post-Schedule Check
PSD	Pre-Solve Deviation
RFM	Reserves and Frequency Management
RMT	Reserve Management Tool
ROM	Rough Order of Magnitude
RTD	Real Time Dispatch
RTP	Real Time Pricing. For the purposes of this report, this is the consideration of real-time energy and reserve prices.
SAD	Stand Alone Dispatch
SCADA	Supervisory Control And Data Acquisition
SDV	SCADA Data Validation
SFT	Simultaneous Feasibility Test tool
SO	System Operator
SODA	Solution Options and Design Approach
SOSPA	System Operator Service Provider Agreement
SOW	Statement of Work
SPD	Scheduling, Pricing, and Dispatch
TAS(C)	Technical Advisory Services (Contract)
TP	Trading Period
TTSE	Training & Testing Simulation Environment
UTS	Undesirable Trading Situation
VOLL	Value Of Lost Load

WITS	Wholesale Information Trading System

1. Executive Summary

The Electricity Authority (the Authority) requested additional details from Transpower, as the system operator, to provide a rough order of magnitude (ROM) cost estimate and delivery timeframe for a real time pricing (RTP) design. A specified RTP design arose from collaborative work between the Authority and Transpower to provide sufficient detail for both the ROM and industry consultation. At the instruction of the Authority the specified RTP design was based on shadow prices derived by Transpower's real time dispatch (RTD) tool.

Dispatch-Based RTP

The specified design would see dispatch prices calculated by the dispatch schedule (RTD)[1] used by Transpower to formulate dispatch instructions. Dispatch prices would reflect the interaction of offered generation and demand-side bids – i.e. a demand-side bid could set spot prices if it was the marginal resource. Each re-dispatch by Transpower would generate new dispatch prices.

Final prices would be calculated by the clearing manager as an average[2]of the dispatch prices in each 30-minute trading period. All load would be priced (including scarcity prices assigned to involuntary load shedding), eliminating the need for provisional pricing processes.

ROM

Transpower's cost to implement the dispatch-based RTP option is expected to be $9.2m, with a lower bound of $7.6m and an upper bound of $11.0m.

Several scope variations were independently costed. These are design options which are expected to deliver increased benefits but are not required to implement RTP. The total for all variations is estimated to be between $255k and $380k. This represents a tolerance within the standard tolerance of -25%/+75%.

ROM Cost	Expected	Lower Bound	Upper Bound
Dispatch-based RTP	$9.2m	$7.6m	$11m
Total Scope Variation	$305k	$255k	$380k

Commissioning is expected to take 40 months from project initiation.

As signalled in Transpower's previous Real Time Pricing Option Analysis report (TASC054[3]), a fully featured RTP solution would have significant business and design impacts. A dispatch-based development would touch large parts of the market system with consequential large project costs and considerable time required. Careful consideration of the selected design approach has resulted in a staged delivery approach, optimised to minimise both risk and duration of delivery.

Once the RTP scope is confirmed Transpower would organise an external review of both the RTP design and delivery plan as part of Transpower's due diligence for a project of this complexity.

[1] A 5-minute look-ahead schedule.

[2] The averaging methodology will form part of consultation; time-weighted being the option recommended.

[3] http://www.ea.govt.nz/dmsdocument/20600

2. Introduction

2.1. Purpose

The Authority has a project in its 2016/17 work programme to consult with industry on an initiative which would result in settlement prices being calculated and published during the trading period; i.e. RTPs.

The project builds on previous work and has been assigned a 'highest priority' status by the Authority. The previous related project (2015/16 year) and industry consultation resulted in selection of a dispatch-based look-ahead schedule as the basis for development of the RTP initiative.

Having nominated the dispatch schedule as the basis for RTP, the Authority requested Transpower investigate and document the implications of RTP based on this choice.

2.2. History

The Authority has engaged with Transpower under two previous projects concerning the Spot Pricing Refinement entry on their work programme;

- Real Time Pricing Option Analysis (TASC 54).
- Hours-Ahead Market Pricing Option Analysis (TASC 57)[4].

Both pieces of work were largely stand-alone, save for how the various RTP and ahead market options might interact.

Real Time Pricing Option Analysis was, by design, broad in its consideration of RTP options. Four 'base-options' were included by the Authority; to which Transpower suggested a fifth. The permutations of key design parameters resulted in a full long-list of approximately 80 options. Distinguishing between primary and secondary parameters enabled the list of options to be reduced to 12. The 12 options were then assessed against criteria aligned with successful delivery of an RTP solution. A ROM costing was provided for the RTP solution option which scored best against the assessment criteria.

The Real Time Pricing Option Analysis breadth of consideration enabled the Authority, after its own assessment, to select the best option for setting RTPs and to progress to further investigation.

An ahead-market is seen as secondary in priority by the Authority relative to RTP. It is covered as an option in the Authority's Making hours-ahead price forecasts more accurate consultation paper[5]. Any ahead-market developments will be progressed independently by the Authority, albeit cognisant of the status of the RTP initiative.

2.3. Terms of Reference

Deliverables due under TAS 60 for a dispatch-based RTP solution are:

- A decisions and assumptions register documenting key market design decisions and assumptions.
- Production of initial Transpower stakeholder requirements.

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[4] Appendix C of the Authority's consultation paper "Making hours-ahead price forecasts more accurate" – link in footnote 5.

[5] *http://www.ea.govt.nz/development/work-programme/pricing-cost-allocation/exploring-refinements-to-the-spot-market/consultations/#c16353*

- A high level technical assessment of the RTP solution sufficient to review the rough order of magnitude (ROM) estimate.
- An updated ROM costing for the remaining phases of the project.[6].
- A TAS Statement of Work (SoW) for the next phases of RTP project work.

The decisions and assumptions register is Appendix 1: of this report. Initial Transpower stakeholder requirements have been provided separately to the Authority. Sufficient high level technical design work was completed to verify the ROM process. The high level technical design is summarised in section 3.2 and covered in greater detail in section 6. The updated ROM costing is provided in section 7. Comment is made on the SoW for the next phase of the RTP project in section 2.5.5.

In addition to the TAS 60 deliverables under the TAS 60 SoW Transpower was also required to:

- Undertake a project complexity and risk review.
- Identify Code requiring development to implement RTP solution.

The complexity and risk review is covered in section 7.2. The Code review process performed under TAS 60 is summarised in section 8. the TAS 60 Code review formed the foundation for detailed Code review work which was undertaken and finished under a separate workstream between the Authority and Transpower.

2.4. Intended Audience

The primary audience for this document is the Authority. This report assumes readers have prior knowledge of the New Zealand wholesale electricity market and real time pricing in a wholesale electricity market context.

2.5. Methodology

From a range of RTP options the Authority has selected a preferred dispatch-based solution for further analysis.

To progress the necessary analysis and review, a project team was established consisting of several Transpower subject matter experts and Authority representatives. Most were involved in the preceding phases of the RTP project.

The project team undertook a five stage process, as requested by the Authority, to prepare the required level of detail required to progress:

1. Risk assessment and decision review.
2. Preparation of initial Transpower stakeholder requirements.
3. Technical assessment of the solution.
4. Revision of the ROM estimate specific to this option.
5. Definition of the scope and plan for the next phase.

[6] This is an update of the ROM provided in the Real Time Pricing Option Analysis report which reflects the increased design certainty specific to this option.

2.5.1. Risk Assessment and Decision Review

Risk Assessment

To define an appropriate risk management approach for the project, an independently facilitated project complexity and risk assessment workshop was undertaken. The objectives of the workshop were:

- To review the RTP project complexity – assess the level of project uncertainty, ambiguity and associated risks.
- To review the process for successfully managing project complexity.
- To provide a summary of key points of the RTP initiative, its key drivers and proposed benefits.

Further details of the project risk assessment workshop are in section 7.2

Design Decision and Assumptions Review

A review of the dispatch-based RTP solution described in the Real Time Pricing Option Analysis report was required to determine outstanding decisions and assumptions requiring further investigation and analysis. This review was undertaken as a series of workshops (including attendance by Authority representatives) and formed the basis for a high level technical design of the solution:

- Workshop 1 – 13 September 2016.
- Workshop 2 – 20 September 2016.
- Workshop 3 – 28 September 2016.
- Workshop 4 – 20 October 2016.

The key decisions identified in these workshops were then further investigated by the project team. (See section 4 for further details of the workshops).

Code Review

An initial assessment of Code amendments required to implement an RTP solution was performed based on the high level technical identified during the design and assumptions workshops.

The assessment generated Transpower's high-level recommendations for regulatory changes and provides an analysis of the existing Code to gauge the extent of the required changes.

A separate, parallel, TAS workstream (TAS63) provided detailed comment on the draft Code changes to assist the Authority with the forthcoming industry consultation. The amended Code must enable the desired RTP design.

2.5.2. Prepare Initial Transpower Stakeholder Requirements

Transpower has developed initial stakeholder requirements for its own internal market (IT) and operational systems based on key decisions and assumptions (Section 4) while incorporating the expected industry impact. To gauge the effect of the solution on the wider industry, output of the Real Time Pricing Option Analysis consultation was considered by the Transpower project team.

Preparation of Transpower's stakeholder requirements served to inform issues raised in this report and assisted with revising the ROM costing for solution development. Following the Authority's consultation with industry the Transpower stakeholder requirements may be revised.

The process for developing Transpower stakeholder requirements included:

- Identifying key requirements.
- Defining workshop approach and topics.
- Requirements workshops - a series of 8 workshops were held to capture all aspects of the proposed solution. The core Transpower project team attended these workshops.
- Documenting and reviewing Transpower stakeholder requirements.
- Approval of the initial Transpower stakeholder requirements by the Transpower project team.

2.5.3. Technical Assessment of the Solution

Following preparation of the initial Transpower stakeholder requirements, a technical assessment was undertaken of the dispatch-based RTP design. Technical specialists worked through the design decisions and Transpower's stakeholder requirements to determine changes required and prepare the ROM cost estimate for project delivery.

A technical assessment of the solution by the project team provided greater detail to highlight the areas of complexity and interrelationship with other systems. Further details of this assessment are in section 6.

2.5.4. Revision of ROM Estimate

As part of Real Time Pricing Option Analysis a ROM estimate was prepared for all RTP options including the dispatch-based solution selected by the Authority.

Following the development of Transpower's stakeholder requirements and a subsequent technical review of the proposed solution, it was apparent the ROM estimates in the Real Time Pricing Option Analysis were no longer useful. A series of three ROM workshops were held on 17-19 January 2017 to build from the ground up new effort and cost estimates for the specified RTP solution.

2.5.5. Define Scope and Plan for Next Phase

The TAS 60 SoW requires Transpower and the Authority to develop a work plan for the next RTP work package. This report is an input to the work plan. The statement of work is likely to include;

- Industry engagement and consultation support.
- Engagement with third parties for assurance activities.
- Following consultation, update of the Transpower RTP initial stakeholder requirements, development of designs and planning for the delivery project.

2.6. STRUCTURE OF THIS REPORT

This report is of the findings of the review and assessment of the selected dispatch-based RTP solution and is as follows:

- Section 3 describes the dispatch-based RTP design and the impacts on the system operator and its systems.
- Section 4 presents the design decisions and assumptions detailed during the market design workshops.
- Section 5 describes other considerations which do not directly affect Transpower but may be relevant for the Authority’s further RTP development works.
- Section 6 details the Transpower stakeholder requirements; the development process and the requirement outputs.
- Section 7 sets out our high level technical assessment of the proposed RTP design.
- Section 8 sets out our ROM and timeline to implement the RTP design.
- Section 9 describes the Code review undertaken and details recommended changes.
- Appendices cover:
    - Additional detail on the Complexity and Risk Workshop report.
    - Complete Decisions and Assumptions register.
    - The proposed bid variations provided by the Authority.

3. Dispatch-Based RTP Overview

This section provides a summary of the selected dispatch-based RTP design (Option 2.1 in the Real Time Pricing Option Analysis report).

It describes the features of the selected design and highlights operational and technical challenges that would need to be addressed to implement the solution.

3.1. RTP Design Overview

Ex-post pricing regimes separate real-time dispatch and the calculation of the settlement prices, allowing pricing anomalies in real-time to be amended after the fact. This cannot happen in a RTP regime; many of the benefits are derived from behavioural change because prices are formed during each trading period. Many changes are required to be made to Transpower's market system to achieve this.

The selected dispatch-based RTP design has been refined in conjunction with the Authority through a series of design workshops. Many of the refinements are efforts to make dispatch schedule prices more accurately reflect marginal prices at all nodes, rather than the current market design which is focussed on ensuring generation is matched to supply.

The following is a high-level description of the specified design. Greater detail is contained in subsequent sections of this report. This section is provided to explain the various schedule and price terms used in this report.

Price and schedule nomenclature

The agreed RTP design would see interim prices calculated as the time weighted average[7] of the dispatch prices published in each trading period. Dispatch prices are calculated by the real-time dispatch schedule (RTD) and would only be published to WITS if dispatch instructions are issued from the dispatch schedule. At the conclusion of each trading period the clearing manager would apply the averaging methodology to dispatch prices to calculate interim prices. In the absence of a pricing error claim interim prices would become final prices the following business day. The market is settled by the clearing manager using final prices.

To maintain the utility of RTP previously published prices would substitute for dispatch prices when they are unavailable; for instance, during a market system outage. When this occurs the last published dispatch price would stand till the end of the trading period, and be averaged accordingly. When a dispatch price is not published at the beginning of a trading period the latest PRSS price for the trading period would apply. PRSS prices used in this manner would be included as though they were dispatch prices in the price averaging methodology.

3.2. High Level Technical Design

Any RTP regime would introduce significant changes from the current ex-post pricing methodology. Key changes for the specified RTP design include:

- No opportunities for manual intervention to remedy infeasibilities and undesirable prices.

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[7] The averaging methodology will be a question in the Authority's consultation paper. Time-weighted averaging will be the recommended option.

- Settlement can occur on prices based on default bids reflective of scarcity pricing.[8]
- Non-dispatchable load is assigned a default bid reflective of scarcity pricing.

Further design features of the dispatch-based solution are listed in the table below:

Table 1: Dispatch-Based RTP Key Design Features

Design Component	Option Selected	Rationale for Chosen Option
Ramp rate	Five minute	Current state for dispatch. Significant operational impacts for power system operation if changed.
Schedule timing	Dispatch prices only published from schedules that are actually dispatched from	Simplify the selection of which schedules to use for pricing. **NB:** Price averaging **is not in scope** as this is an NZX consideration.
Market System outage	PRSS prices substitute dispatch prices	Most recent actionable price published.
Publication outage	Interim prices calculated from published dispatch or PRSS prices as applicable[9]	Most actionable price.
Generation initial conditions - SCADA outage	Revert to last dispatch values	Existing functionality for dispatch schedule
Dispatchable demand	Include DD bids	Retention of DD in final price calculation
Non DD load	Forecast value assigned default bids reflective of scarcity bids	Assigns a price to all load for inclusion in scheduling and dispatch processes
Price averaging	Time weighted by clearing manager	Aligns with schedule timing choice
Energy offers	Static for half hour	No change required for RTP **NB** Dynamic offers costed as an option
Transmission offers	Dynamic with electronic re-offer - status quo	Status quo for dispatch and aligns with energy offer option choice
HVDC offers	Dynamic with electronic re-offer - status quo	Status quo for dispatch and aligns with energy offer option choice

[8] Hereafter scarcity bid(s) or scarcity prices (in context). See section 4.1.1 for details.
[9] To be actionable a price has to be visible.

Design Component	Option Selected	Rationale for Chosen Option
Final Prices	Initially Interim with price error process retained	Retention of current market functionality
Contingent Event (CE) Instantaneous Reserve (IR) constraint violation penalty (CVP)	Values to be advised by the Authority	Values need to be updated to reflect the impact of the default load bids reflective of VOLL
Outage Infeasibilities	Proxy prices assigned based on reference price and historical location factor	Avoids mismatches between price (either $0 or scarcity) and presence of load
Scarcity and High Spring Washer	Default bids reflective of VOLL/scarcity. With no electronic dispatch of load shedding (i.e. load shedding continues to be done by phone). Schedules track load not served to reflect scarcity until all load restored	Removes complexity and separate initiative for auto load shedding.
Re-solve Simultaneous Feasibility Test (SFT) / Reserve Management Tool (RMT)	No change to existing processes	Existing processes are fit for purpose
Forward schedules	Align schedule designs (excludes five-minute security issues)	Forward schedules give the best indication of likely final prices

3.3. Impact on Transpower Processes

The move to a RTP regime based on dispatch would significantly impact Transpower operational processes. Existing scheduling and dispatch processes are designed around ex-post pricing process. Reorienting them for ex-ante pricing requires significant change.

Ex-post pricing allows Transpower to focus almost exclusively on security in real-time. The current dispatch schedule is aligned to this mode of operation; it is designed to support meeting the principal performance obligations (PPOs) by dispatching generation and IR to keep frequency within the allowable limits.

The processes affected are detailed in this section.

3.3.1. National Co-ordination Centre (NCC) Operations

Under RTP dispatch and pricing of the power system are proposed to occur from the same schedule. With the absence of a stated requirement to alter current dispatch processes this should 'on paper' not have any impact on the dispatch components of Transpower's delivery of the SO service. In reality pressure, real or imagined, would exist to minimise the pricing effects of operational decisions, placing a higher burden on operational staff to manage both the power system and the market concurrently. Given settlement and dispatch are to be derived from the same schedule, there would be a perception of added responsibility with setting prices when dispatching.

The RTP process would need to automate a number of existing manual business process tasks related to the handling of different classes of infeasibilities which occur currently and at the same time review any consequential impact of RTP on coordinator workload.

Impacts that dispatch-based RTP may have on NCC are described in further detail in the following paragraphs.

Discretion

The Code affords the SO the ability to alter, or deviate from, the dispatch schedule to maintain its PPO's. This is referred to as discretion. As mentioned previously, the SO's primary real-time focus is on the provision and maintenance of power system security. An example of discretion is the application of a constraint to the dispatch schedule which limits a generator's output. Such a constraint can be to affect a minimum or maximum output. When such constraints bind the intended outcome is to maintain security. When a constraint binds it must have caused a deviation from the, otherwise, optimal solution. This deviation may result in a pricing impact.

Historically participants' interest in the SO's use of discretion has centred on its contribution to constrained on costs. The exclusion of discretionary constraints from the final pricing schedule means the industry has not had reason to query their impact on settlement prices. In the RTP design proposed the dispatch schedule would be used to calculate settlement prices. Consequently, discretionary constraints would be included in the determination of settlement prices. The SO is confident its use of discretion will continue to be justifiable. Nevertheless, this change may bring pressure to bear on the SO to act differently; the participants' goal being to effect a change in settlement prices.

Judgement

In a more literal sense the SO also exercises judgement which is different to the discretion provisions explicitly included in the Code. This behaviour is afforded through other less prescribed sections within the Code. For example, there is no prescription on the frequency within a trading period with which dispatch instructions must be issued. In trading periods in which load and intermittent generation change very little dispatch may be less frequent than during those in which load, in particular, is changing rapidly. RTP would not alter this, dispatch price publication is contingent on the issuing of dispatch instructions.

Scarcity bids

The inclusion of scarcity bids in the dispatch schedule is in many respects a like-for-like with the current CVPs[10]. There is a significant difference; under RTP there would not be any revision of dispatch prices prior to their use to calculate interim prices. Under the current ex-post pricing regime infeasibilities are resolved prior to prices becoming interim. It should be noted this process gives no certainty of price. Further, final prices are currently unbound except for the application of the administered scarcity pricing regime or the application of the High Spring Washer Pricing Situation (HSWPS) process.

The impact of scarcity bids in the dispatch schedule is not only limited to price, it also indicates an inability to fully supply load, or when to do so would be 'uneconomic'. This may be at a single GXP or across several GXPs. Cleared scarcity bids in the dispatch schedule may signal the need for load-shed to occur.

The number of instances of non-supply due to a shortage of generation offers is not expected to change under RTP. There is no relationship between offered capacity and the inclusion of scarcity bids in the schedules. Consequently, the rate of occurrence of security situations affecting the ability to supply load should be unchanged.

Load-shed

The presence of cleared scarcity bids in the dispatch schedule may create implicit or overt obligations on the SO to take certain actions. These align to two possibilities for the presence of VOLL in the dispatch schedule:

- In alignment with a security situation.
- In the absence of a security situation.

In situations when scarcity bids clear in the dispatch schedule in alignment with a security situation, load shed would be instructed to return the power system to secure operation. The cleared scarcity bid quantities assisting, but not prescribing, the actions the coordinator takes. With the retention of phone dispatch for load-shed it is not practical to instruct load-shed in the detail with which the dispatch schedule may clear scarcity bids.

This operational policy would also cover the possibility for a security situation to be precipitated by the presence of cleared scarcity bids in the dispatch schedule. In this situation the quantity of cleared scarcity bids in the dispatch schedule is the means by which SPD has balanced supply and demand, i.e. with a quantity representative of non-supply. When this occurs the coordinator would also have to instruct load-shed to maintain frequency and compliance with the PPO's[11].

Scarcity bids may clear in the dispatch schedule in the absence of a security situation. This may be due to discrepancies between the model of the power system used by SPD and that used for real time contingency analysis [12] or because the quantity of scarcity bids cleared is insignificant. In this situation the coordinators would not instruct load-shed. The coordinators

[10] In as much as a situation where an infeasibility would occur now and CVPs be present in the schedule results scarcity prices would be present instead.

[11] Assuming dispatch instructions are issued from that dispatch schedule and the quantity of cleared scarcity bids is material.

[12] All schedules are a modelled representation of the power system. Differences therefore can occur between reality and schedule results.

may take action to remove the cause of the scarcity prices from the dispatch schedule. However, given these actions would be taking place within a real-time control centre such action would be on a reasonable endeavours basis.

These operational policies are unchanged from those employed currently. Load-shed is only instructed when there is a security situation.

Scarcity bids and load-shed - concerns

Transpower accepts there may be divergent views to Transpower's concerning action which will be taken when scarcity prices are present in the dispatch schedule but a security situation does not exist. Transpower therefore, looks forward to working with the Authority and industry to clarify expectations and deliver certainty with regard to load-shedding procedures under RTP. Certainty of operational actions will help to deliver certainty of price in this regard, one of the goals of RTP.

Transpower further notes the Authority and industry expectations concerning the application of load-shed to be implemented under RTP would need to reflected in the Code. An important aspect of this is the need to ensure alignment in the Code between the dispatch of the power system under Pt.13 and load-shed provisions in Pt.8. Currently the load-shed provisions in pt.8 are written on the basis of emergency situations. It is possible under an RTP regime with scarcity bids for load-shed to be 'economically' driven; a physical solution exists but is more expensive.[13]

Load-shed and EDBs

A discussion point concerning load-shed is the load is, more often than not, controlled by the lines company. Few lines companies are market participants. Load-shed is instructed from the SO coordinator to the GO coordinator who then contacts the line company and advises the load-shed actions required. As noted before these instructions may be pragmatic variations of the cleared scarcity bids in the dispatch schedule. This 'chain-of-command' remains in place post RTP. The RTP ROM was undertaken on the basis of the status quo remaining.

The infrequency with which instructed load shed occurs may create a reluctance by EDB to invest capital in tools and systems to electronically receive load shed instructions from the SO. Future developments in this area need to be carefully managed. To future-proof this step the SO's tool changes would include the ability to dispatch generators, and IR providers separately to load.

A design variation for electronic delivery of load-shed instruction to EDBs via the EDF phase 3 platform was separately costed. See section 0.

Dispatchable Demand

The dispatch schedule is a key mechanism by which the SO delivers real-time security to the power system. Including dispatchable demand (DD) in the dispatch schedule would effectively make DD a real-time 'security product'. The Authority should work through the implications of this change with current and prospective DD participants.

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[13] For instance, uncleared generation may exist which is more expensive to schedule than scarcity bids.

Contingent Event Instantaneous Reserve Constraint Violation Penalty

Under RTP the contingent event (CE) instantaneous reserve (IR) constraint violation penalty (CVP) would be set by the Authority. The values chosen would need to reflect the co-optimisation which occurs when a schedule solves.

Consequently, the CE IR CVP values would have to be low enough for both the fast instantaneous reserve (FIR) and sustained instantaneous reserve (SIR) CE CVP to be less than the lowest priced scarcity bid. This could have the following results:

- Generation offers priced lower than the scarcity bids being left uncleared and potential load-shed signalled as a result.
- Where the CE IR CVP is set too low then it may clear, instead of IR offers. This may result in a less secure power system.

Transpower understands and agrees the two outcomes described above are in-line with the intended results of an RTP regime: assignation of load-shed prices gives greater certainty and the least cost solution is dispatched.

However, we have concerns regarding the variable nature of the offer stacks, the static nature of the CE IR CVP and the results of co-optimisation giving rise to the possibility of unintended consequences and sub-optimal results.

Market queries

As detailed in this section there is the potential for an increase in market and price related queries to be made in real-time than presently. It is expected these increases would align with the transition to a RTP regime and the occurrence of specific pricing events. Resourcing requirements to enable answering of participant queries would be planned by Transpower in alignment with these expectations.

3.3.2. Other Operational Impacts

Transpower's roles as both SO and grid owner (GO) in the resolution of provisional price situations in the final pricing schedule cease with the implementation of RTP. The SO is required to provide revised data to the pricing manager to resolve infeasibility situations and high spring washer pricing situations (HSWPS). The GO is required to provide revised data to resolve SCADA situations and metering situations.

The GO is currently obligated to provide metering data to the pricing manager by 07:30 daily. This data's primary usage in the final pricing schedule. Cessation of the final pricing schedule suggests this data may no longer need to be retained? Transpower recommends the provision of this data be retained; the obligation to publish this data implies the data is used by parties other than the pricing manager.

To fully replicate the current dataset, the obligations on parties to provide metering information to the GO must be retained. The GO's obligations would be changed to reflect the new receiver of the data; that party then being responsible for publishing the data. The current timeframes reflect pricing manager's deadlines. In the absence of these deadlines the current publication timing could be relaxed.

Transpower would no longer be required to sub-lease SPD to the pricing manager, nor support the pricing manager's installation and use of SPD.

Minor adjustments may need to be made to assessment of planned outages if the proxy price assigned during outages, as proposed by Transpower, is applied to the forecast schedules. Part of the assessment of planned outages is the presence of infeasibilities, CVP prices and disconnected node status. The first two checks would no longer be relevant if the proposed changes go ahead. The assessment process would need to be changed to place greater emphasis on the disconnected node status.

3.4. IMPACT ON SO SYSTEMS

An RTP solution that meets expected Transpower stakeholder requirements would require changes to every core component of the market system.

Changes are required for both dispatch and forward schedules, and would variously touch on: sources and modelling of input data, pre-processing, post-processing, workflow, electronic dispatch, schedule publication, operator interfaces, downstream data processing and backup dispatch systems.

The extent of the expected RTP impact on SO systems is illustrated in figure 1.

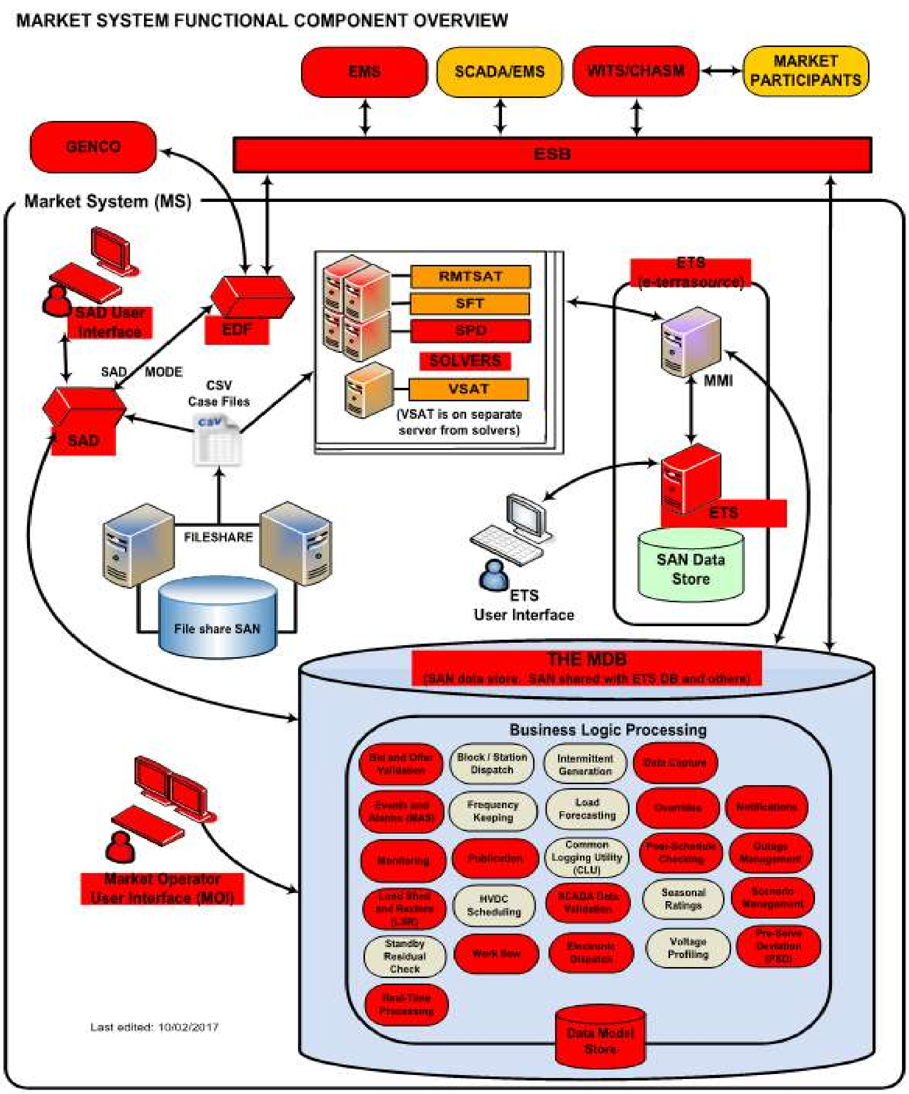

Figure 1 -impacted market system components

Such a wide-reaching and complex change brings inherent risks. To implement RTP would also require many external parties (e.g. service providers and market participants) processes and systems to be modified.

Particularly extensive changes are required to support the change to economic clearing of conforming load in the market schedules (see sections 3.5 and 4.2.9). This alone would require changes across most components of the market system, and is a significant project in its own right. Among other changes, the proposed design is expected to require development of relatively complex logic to account for curtailed load quantities in subsequent dispatch solutions, as well as new operator interfaces to manage the load shed and restore process under the new regime.

Changes required to support electronic dispatch of various demand types touch a wide range of system components, including key operator interfaces and complex areas of business logic processing, as well as new external interfaces to an uncertain number of new dispatch entities.

Additionally, the proposed design would require significant design and implementation to manage the decommissioning of the current Final Pricing and RTP schedules, while maintaining these functions in parallel with the new RTP regime across a cutover window.

3.5. Impacts on Demand Side Participation

In addition to the potential impacts to EDB mentioned in the previous section there are intended to be changes to the existing DD regime and the introduction of 'dispatch-lite'. How RTP would affect participation in DD and other demand side programmes is described in this section

3.5.1. Dispatchable Demand

Dispatchable demand (DD) was introduced to the wholesale electricity market to enable demand-side participants to have certainty over consumption decisions and to put downward pressure on spot prices. Dispatchable bids are included in the schedule from which settlement prices are calculated, currently the ex-post final pricing schedule. DD is dispatched from the NRSS schedule published prior to the start of the trading period to which the bid pertains. Notably, DD is dispatched using WITS, not the mechanism GENCO/EDF system used to dispatch generators and IR.

Impacts on DD would arise from the inclusion of dispatchable bids in the dispatch schedule, resulting in the dispatch of DD in a 5-minute timeframe (like generation and reserves). The requirement to receive real-time dispatch instructions is assumed to be mitigated by Transpower's EDF Phase 3 project[14]. This should enable DD participants to receive real-time dispatch instructions without the need for a Genco connection. Nevertheless, this is still an increase in requirements compared to the existing DD dispatch arrangements. Currently, DD participants receive dispatch instructions via a WITS display.

Challenges

Real-time dispatch may not, however, be achievable or desirable for current and prospective DD participants. When DD was included in the Code participants expressed concern regarding including DD dispatch in the real-time dispatch process. Consequently, dispatch is from the 30-minute NRSS. This decision was based on two main points; it was cheaper and simpler to implement, and it was easier for participants to participate in and comply with. The ease of

[14] A RTP project assumption is the EDF Phase 3 project is completed prior to RTP

participation was based on the timing of DD dispatch allowing participants to plan to comply with instructions and it avoided potential 'saw-tooth' dispatch instructions[15]. 'Saw-tooth' dispatch occurs when a load is marginal and alternates from on to off and vice-versa to balance supply and demand in consecutive dispatch instructions.

Possible mitigations

Previously discussed mitigations to the issues which may face current and prospective DD participants are included below. These changes have not been included in the ROM costing.

A possible mitigation for 'saw-tooth' dispatch would be the inclusion of ramp-rates and minimum cycle times[16] to dispatchable bids. If implemented these changes would also help clarify the expected response to dispatch instructions. This was discussed during the inclusion of DD in the Code and raised by a DD participant in recent discussions. Attaching ramp rates to bids has not been included in the ROM.

While including DD bids in the dispatch schedule appears 'mandatory' it may be possible to continue DD dispatch from the NRSS. To enable this, the dispatch schedule load must be adjusted to account for the difference between the dispatched DD quantities (NRSS) and cleared DD quantities in the dispatch schedule. The solution is not straightforward, the difference between the 2 quantities would not be known until the dispatch schedule solves, yet the difference needs to be an input of the dispatch schedule.

Using this methodology would ensure the total load required to be met in the dispatch schedule would be correct. However, it would likely result in a loss of efficiency of the RTP particularly in the case where DD had been 'over dispatched' with regard to the RTP dispatch. In such situations, the efficiency of not scheduling the DD bid which could not be satisfied would still be included in the schedule, negating some of the pricing efficiencies of DD's inclusion in the RTP schedule.

Metering obligations

Removal of the final pricing schedule would remove the obligations requiring DD participants to provide daily metering files to the GO. However, the obligation to meter the DD load and provide values monthly to the reconciliation manager would remain. As is now the case this metering data must be from a revenue quality metering installation.

3.5.2. DISPATCH LITE

The Authority has proposed a 'dispatch lite' category be included in the RTP design. 'Dispatch lite' participants would bid their controllable load in to the market through a new bid type (see Section 4.2.9). 'Dispatch lite' bids would be included in all market schedules and therefore be able to set the price[17]. Cleared quantities would be issued to the purchaser from the dispatch schedule (WITS and EDF Phase 3) and compliance assessed against these instructions. Due to a lower threshold for participation and the ability to 'opt-out' after receiving dispatch instructions 'dispatch lite' participants would be ineligible to receive constrained on or constrained off payments.

[15] Referred to as 'yo-yo' dispatch in previous DD consultations.

[16] For instance, how long a load will be off for following a shut down.

[17] The marginal cost of supply could be met by a reduction in a cleared 'dispatch-lite' bid.

Concerns

The ‘Dispatch lite’ concept raises concern for Transpower due to the potential security impact to provision of the SO service. The former being subject to the quantum of load involved and the discrepancy between ‘dispatch lite’ instruction and actual consumption

Transpower notes the market implications of the inclusion of ‘dispatch lite’ is the ability for prices to be formed on trades which are not subject to dispatch and the associated compliance aspects. The Authority and industry needs to carefully consider the implications of this.

Need

The changes to DD as a result of the removal of the final pricing schedule means participation in DD would be less onerous than currently. This may beg the question whether ‘dispatch lite’ is in fact necessary? This is a matter the Authority should covered in forthcoming industry consultation on RTP.

3.6. RECOMMENDATIONS

Our recommendations cover industry consultation and the proposed RTP design.

3.6.1. CONSULTATION

Good engagement with industry is critical to the success of a complex project such as RTP. A step-change such of this nature makes it essential participants are fully aware of the implications and provide comprehensive response to consultation.

Targeted effort should be made to engage with demand side providers (current and potential) particularly as RTPs benefits and impacts lie most heavily with the demand side. EDB input should also expressly be sought.

Certain aspects of the RTP design require industry consideration to ensure the solution is fit-for-purpose. In particular, the following matters have special impacts which require industry support: impacts on the demand side, the introduction of and settlement on scarcity bids, the data publication requirements, the treatment of transmission outages and assessing ability to respond to RTP signals.

3.6.2. DESIGN

Transpower recommends the RTP design strikes a balance between pragmatism (both operational and market) and cost/complexity. The decision to retain the pricing error claim process affords protection from undesirable pricing outcomes which may arise very occasionally. Therefore, it may not be necessary to engineer a tools-based solution for some of the pricing outcomes possible under an RTP regime.

4. DESIGN DECISIONS AND ASSUMPTIONS

To perform the ROM as requested it was necessary to agree a design with the Authority. The outcome of this process being what we describe as 'the specified design'. It is the Authority's role to determine the final RTP design and what progresses to a delivery phase. We expect that would follow an industry consultation process.

Transpower created a base register document containing a mix of open design questions and assumptions based on the work completed in the Real Time Pricing Option Analysis report. Over a series of workshops (attended by both Authority and Transpower staff) these matters were considered and adopted, or not. A register of decisions was retained.

The specified design decisions and assumptions formed the basis for the high level technical assessment and ROM preparation. Through the ROM technical assessment and initial Transpower stakeholder requirement process the design and assumptions continued to evolve. The specified design settled on for ROM costing was verified with the Authority prior to being undertaken.

The section describes each of the design decisions and assumptions. The complete market design decisions and assumptions register is in Appendix 1:. For clarity this is grouped by those concerning schedule inputs, the calculation of the RTP price, the forecast schedules and 'other design considerations'.

4.1. INPUTS

Numerous changes to the inputs used in schedules would be required to implement RTP. Those identified from the design used for the ROM process are detailed.

4.1.1. SCARCITY BIDS

The inclusion of scarcity bids to the market optimisation achieves two key RTP requirements, both of which are needed to fully realise the benefits of RTP:

- The manual interventions currently required to address infeasibility situations, HSWPS, and Scarcity Pricing are replaced.
- All load has a non-supply price.

Scarcity bids allows for an economic solution to be produced upon which settlement can be based. The requirement for prices to be actionable is not met if some prices are subject to manual revision and delayed publication, essentially a replication of the one of the main drivers for implementing RTP.

Adding scarcity bids to the optimisation does not address the physical imposition (lack of supply or transmission) which would, in the absence of scarcity bids, result in an infeasibility situation. Rather, scarcity bids 'undercut' the non-economic CVP values with economic values. In the absence of scarcity bids all load would not have a non-supply price; non-priced load would be subject to the application of the load shed provisions contained within the grid emergency procedures. Scarcity bids would apply to all non-dispatchable load in the dispatch schedule.

To apply the possibility of non-supply equitably scarcity bids need to be graduated to spread the impact which would otherwise accrue disproportionally at certain GXPs/regions; those which are costliest to supply are assigned supply deficits by SPD to minimise total system costs. When scarcity bids are marginal in the solution the price impact will 'bleed' from the GXP where non-supply has been scheduled to others within the affected region. This pricing effect is observed now in shortage situations when the deficit generation CVP ($500,000/MWh) is present in a solution. Prices at other GXPs in the affected region are derived from an increased ‘purchase’ in the deficit generation CVP.[18]

The inclusion of a non-supply price within the optimisation begs the question: to what degree does the presence of non-supply prices in the dispatch schedule require aligned load shed action? The quantity of non-supply being the volume of load which has not been met in the optimisation and has been assigned scarcity bid prices.

The introduction of scarcity bids to the solution effectively introduces a price cap, in-line with the current scarcity pricing regime, on generation offers. Scarcity bids would be cleared before offers which are priced above the scarcity bids. The pricing effect of losses means a generator offer slightly less than scarcity bid prices may exceed scarcity bids at a GXP and scarcity bids would clear instead. The solver would not distinguish between a solution which includes load shed and one which does not; it is required to solve for lowest cost. If this involves scheduling load shed, “so be it”. The related discussion of the co-optimisation of IR and energy and the effect this could have in relation to the clearing of scarcity bids is discussed in the next section.

Scarcity bid prices would be set by the Authority. For use in the design consideration and ROM the Authority has advised the following values to be used for scarcity bids at conforming GXP.

Table 2: Scarcity bids Prices

% of load	Scarcity bids price
5%	$10,000/MWh
15%	$15,000/MWh
80%	$20,000/MWh

4.1.2. CE IR CVP

To maintain the industry preference for IR deficits to occur before load shed, when there are insufficient offers to meet both the energy and IR requirements, the CE IR CVPs must be revised to trigger before scarcity bids. The potential for a FIR and a SIR deficit to occur simultaneously imposes a further requirement; the total of both the FIR and SIR CVPs must be less than the lowest scarcity bid price. Failure to do so could result in physical generation offers remaining uncleared when load is shed.

IR shortages occur when there is a lack of capacity and the solver has to choose between scheduling energy or IR; the full requirements of both being unable to be met. If there are sufficient energy offers available which do not increase the CE risk IR shortages do not occur. When an IR shortage does occur the output from the CE risk[19] is minimised to reduce costs and the CE risk’s offers are the energy component of the marginal cost of supply. In these situations, realising the marginal MW of energy would increase the CE risk. Consequently, a

[18] This increase does not equate to a 1:1 basis due to the decrease in losses which occurs when either a scarcity bid or CVP quantity is used. Neither of these need to be transmitted as they are ‘located’ at each GXP. Consequently, to ‘retract’ a physical MW which is being sent along the path of supply does not require a 1:1 replacement as 1MW was not arriving ‘further-down-the-chain’.

[19] Either a generator, the HVDC, or very occasionally an AC transmission asset.

corresponding increase in scheduled IR would be required too. In an IR shortage situation, the IR component of the marginal cost of supply is the CE IR CVP(s). Therefore, the marginal cost of supply is the CE risk energy offer plus the CE IR CVP(s). Should the marginal cost exceed the scarcity bid then the scarcity bid would clear as the cheaper option. The clearing of a scarcity bid indicates a need to load-shed. This outcome would be contrary to the industry's agreed preference for CE IR deficits to occur before load-shed. Hence, the need to reduce the CE IR CVP(s).

Care also needs to be taken to ensure the CVPs for CE IR deficits are not set too low. If they are they might be used more than is intended, leaving a physical solution 'stranded' on cost. For example, if the CE IR CVP are set to $2,000/MWh, the 'CE risk' at $500/MWh, and 'generator A' at $3,000/MWh it would be cheaper to incur an IR deficit when the IR offers total less than the 'CE risk' offers then it would to clear 'generator A'. Where this to occur full N-1 IR would not be achieved when, based on offered quantities, it could be.

A possible solution would be to allow price reductions to be made to offers inside gate-closure and within the current trading period. Doing so would allow the constraint risk generator to reduce their offered price to clear a higher volume if they so wish. Equally IR providers could reduce their offered prices so they clear instead of the CE IR CVP. There would not be a security incentive for the generator or IR provider to do this; rather their driver would be to maximise generation and IR volumes at a time of high market prices.

4.1.3. IG and Type-B co-generation

IG and Type-B co-generation are handled differently[20] to other generators within the dispatch schedule. Moving settlement pricing from the final pricing schedule to the dispatch schedule changes the way IG and Type-B co-generation is included in the 'settlement schedule'.

Currently IG and Type-B co-generation output is included in final pricing as metered 'negative load', the offers are discarded. Altered offers for IG and Type-B co-generation are included in the dispatch schedule. Under the RTP proposal settlement prices would be calculated as an average of dispatch prices. Therefore, IG and Type-B co-generation would move from metered quantities to offered quantities in the calculation of settlement prices. The impact on accuracy of the settlement price should be minimal, any large changes in output from IG and Type-B co-generation would trigger a re-dispatch of the power system and the associated publication of revised dispatch prices.

To introduce RTP there is no need to alter the treatment of IG and Type-B co-generation for dispatch, and any changes in this area are out of scope. Transpower does not believe this approach will cause any issues to arise.

4.1.4. Generator ramp rate

Complex Ramp Rates

Ramp rates form part of generation offers and reflect the generator's ability to alter the output of their plant. Ramp rates are currently simple by design; for each offered plant an up and a down ramp rate is offered for each trading period. The ramp rates themselves being the offered maximum rate of change over an hour.

[20] For details refer to Appendix C of the report available at http://www.ea.govt.nz/dmsdocument/18368

Occasionally the current simple ramp rate offer regime is found wanting. For instance, when a thermal plant is starting from 'cold'. In this situation the offered ramp rate does not reflect the elapsed time the generation unit start up sequence takes. Additionally, some generating plant have differing ramping abilities depending on their output level.

To improve the price signals RTP would deliver it was considered whether more complex ramp rate offers should be part of the RTP project.

Ramp Rate Horizon

The dispatch schedule forecasts load at a point in the future and schedules generation to meet the predicted load. Currently this happens on a 5-minute horizon basis; matching generation capable of altering output within 5 minutes to the expected load in order to balance supply and demand.

In addition to the form of the ramp rate offers it was also considered whether the dispatch schedule be altered to dispatch generation further in to the future than the current 5-minute horizon. While this may smooth some of the spikiness the utilisation of 5-minute ramp rates[21] can bring, it would have an unknown impact on power system security. It could also create confusion amongst generators as instructions issued every 5 minutes queue up awaiting their future actions. The actual response of generators, either faster or more slowly than instructed could create issues too.

Decision

Neither a change to ramp rates or the dispatch horizon are necessary to implement RTP. It was agreed these changes are out-of-scope for the RTP project. While there may benefits from inclusion to the RTP project, they would add significant complexity which is not necessary to deliver RTP. Any consideration of changes to ramp rates should fall within a separate focussed project.

4.1.5. Bids and Offers

Currently bids and offers must be submitted prior to the start of the trading periods to which they apply. This is reflected in the bona fide provisions contained in the Code which allow revised bids and offers to be submitted between gate closure and the start of the trading period. The inability to revise trades intra-period is managed by manual coordinator actions. For system security purposes grid configuration changes can already be made intra-period. The status quo is included in the RTP design used to produce the ROM costing.

Variant

A variation is proposed to allow revised bids and offers to be submitted within the current trading period to be enabled as part of RTP. It is intended this change would only be allowed in circumstances very similar, if not identical, to the current grid emergency and bona fide provisions. Monitoring would be required to ensure compliance.

Enabling this functionality aligns with the RTP design element of striking of intra-period dispatch prices which are then averaged to become the settlement price. Calculating settlement prices

[21] One twelfth of the offered hourly ramp rate.

in such a way affords freedom to consider this change which the current final pricing regime based on initial conditions does not.

This change would also allow for better identification of costs attributable to the use of discretion in the dispatch schedule. In order to reflect advice received of revised generation or IR provider capabilities, discretionary constraints are applied to the dispatch schedule by the SO. In effect these are indistinguishable from actual use of discretion.

Further it may also mitigate potential issues which may be encountered under an RTP regime; for instance, see section 4.1.2. It is also required to enable Transpower's alternate solution to the Authority's request to enable 'opt-out' bids, see section 4.2.9.

This variation was separately costed for the purposes of the ROM. See section 0.

4.1.6. Bid Types

There are no changes proposed to the generic form of bid information. Bids would continue to provide quantity and price information, either for the total load or for a variance from normal consumption.

The proposal to create a new 'dispatch lite' option[22], a halfway house between DD and non-signalled response, would require the creation of a new bid type(s). The existing DD bids, nominated non-dispatch bids (Non-DD non-conforming GXP) and difference bids are retained. See Appendix 2: for the table provided by the Authority.

Mapping the Authority's bid table against the current market system codes results in the following bid types.

Table 3: Bid Types

Market system bid code	Descriptor
ENDL	A DD bid. May be either dispatchable or non-dispatchable on a trading period by trading period basis. Bid is for total quantity.
ENNC	A non-dispatchable bid at a non-conforming GXP. Bid is for total quantity.
ENDF	A difference bid; a variation against normal in response to price at a conforming GXP. Non-dispatchable
ENXX	A 'dispatch lite' bid at a non-conforming GXP. (self-dispatch)
ENZZ	A 'dispatch lite' bid at a conforming GXP. (self-dispatch)

4.1.7. Non-bid Load

Currently conforming load is represented in the dispatch schedule by a top-down 'load forecast'. The 'load forecast' being the current system load modified for the change in load which is expected to occur over the next 5 minutes. The 'load forecast' values are then assigned to GXP in a pro-rata fashion using each GXP's current actual load. The source of the actual load is the SO's SCADA Data Validation (SDV) data process within the market system. SDV assesses sampled SCADA data against quality and threshold criteria. Data which fails

[22] As discussed in section 3.5.2.

validation is then replaced by the next best quality data following a preordained hierarchy. The best quality data at the end of the validation process is used. This methodology is fit for purpose for a schedule which is dispatching generation to maintain frequency.

Under RTP it is proposed to move from a top-down 'load forecast' to a bottom-up load forecast. The benefit being a greater degree of accuracy of load at the GXP level. The introduction of scarcity bids and the possible ramifications for both load shed and settlement pricing means each GXP's load should be as accurate as possible. Noting the move to an ex-ante schedule would result in a reduction in accuracy when compared to an ex-post schedule.

A variation to the RTP design was separately costed where the GO's ION meter data would be the preferred primary data source. SCADA data would then be the second highest priority within the SDV processing; with all of the other alternate sources moving one level lower down the quality hierarchy. See section 0.

4.1.8. HVDC Configuration

Several of the inputs associated with the HVDC configuration are fixed for use in the dispatch schedule for the duration of the trading period. Others are dynamically calculated and can change during the trading period. These settings reflect the current ex-post 30-minute final pricing schedule, the calculation of RMT values from a 30-minute schedule, and the dynamic nature of elements of the HVDC operation. The move to a 5-minute ex-ante schedule releases any 'locks' the current final pricing schedule may impose on HVDC inputs to the dispatch schedule.

No HVDC configuration changes are required to implement RTP. HVDC modelling in the dispatch schedule will be considered in detail in the next phase of the RTP project.

4.1.9. Generator Unit Samples

Manual intervention is currently required in final pricing if a SCADA situation is declared due to either a data quality or a data completeness issue with the generation unit samples.

Under RTP manual processes such as the resolution of SCADA situation are untenable. The RTD schedule already contains automated back-up data sources for generation unit samples. Therefore, there is no change to the current generation unit sample process. Transpower does not believe this approach will cause any issues to arise.

4.1.10. Gate Closure

The Authority's market initiative which reduces gate closure from 2 hours to 1 hour is scheduled to go-live in Q4 2016/17.

No changes are expected to Gate Closure to introduce RTP. The RTP solution would be implemented with the Gate Closure period that applies at the time.

4.1.11. SFT and RMT

The solver for each of these auxiliary tools used by the SO would not be changed as part of RTP.

However, the results from both SFT and RMT used as inputs to the dispatch schedule would be altered to be those calculated from iterations with the PRS schedule type.

Currently SFT solves following PRS schedules, the results from those SFT solves are only used in subsequent PRS schedules. RMT does not presently solve following PRS schedules.

4.2. PRICE CALCULATION

This grouping of changes relates to the calculation of both the dispatch price and settlement price. These are also changes to the dispatch schedule as the selected design would create both dispatch instructions and real time prices simultaneously. The impacts of some of these changes on the provision of the SO service were covered in detail in section **3.3**.

4.2.1. SCHEDULE TIMING AND DATA PUBLICATION

The dispatch schedule will continue to be solved in regular 5-minute intervals and on an 'as needs' basis. Similarly dispatch instructions will continue to only be issued on an 'as needs' basis; with one of those needs being to issue instructions at least once per 30-minute trading period, preferably at the start of the period. RTP imposes no additional obligations on the issuing of dispatch instructions, and therefore dispatch price publication. The goal of RTP is to set price commensurate with dispatch, not to drive a change to the dispatch process.

However, this does not mean changes in dispatch price will be 'missed'. For there to be a material price change there would have to be an associated material difference in scheduled quantities. Such a change in scheduled quantities would be dispatched and dispatch prices published.

Dispatch prices and associated datasets would be published to WITS when dispatch instructions are issued. The intention is to publish a dataset similar to those of the NRS/PRS schedules from the dispatch schedule.

Currently very limited information is published to WITS from the dispatch schedule. The current WITS RTD datasets are published upon completion of an RTD schedule, irrespective of whether or not it was dispatched from.

The final pricing datasets published to WITS are a combination of results from the schedule and inputs to the schedule. Aligned to the current production of settlement prices they are all 30-minute data, comprised from a mix of parties obligated to publish data either via the Code or via service provider contracts. Consultation should be sought on which of these datasets are required to continue to be published in light of the RTP changes? For instance, does the publication of 30-minute average metering data continue to be needed if the load from each dispatched RTD schedule is published?

As an example it has been identified that a single value for arc flows for each 30-minute trading period will continue to be required as it is used in the monthly loss and constraints processing. This case is somewhat unique, only a subset of this dataset is published[23]. Nevertheless, the data source is the final pricing schedule. A schedule which would cease to exist post-RTP.

Careful consideration would be needed to define the methodology for the production of any substitute 30-minute datasets from RTP data. The non-linear nature of the interactions between the dataset means simple averaging can distort inter-relationships between the datasets. For instance, if a transmission constraint binds causing significant price separation in two dispatch schedules within a trading period the averaged values would not tell the story; the average prices would have some degree of price separation but the average transmission constraint

[23] Those arc flows with flows exceeding 85% of their flow limits.

flow would not be binding. At the dispatch schedule dataset level, the cause and effect would be apparent.

4.2.2. Settlement

Settlement will continue to occur in 30-minute trading periods on a calendar month basis. Changing to 5-minute settlement periods could increase benefits. Undoubtedly such a change would increase costs for delivery. Significant change would be expected to be required to both the clearing manager's and reconciliation manager's systems. Equivalent changes would also need to be made to participants' systems.

Shortening the settlement period is not necessary to implement RTP. Attempting to do so concurrently with introducing RTP presents undue risks to the RTP project. A subsequent revision of the settlement period post RTP deployment would align with the Authority's preference for incremental change.

4.2.3. Infeasibilities, HSWPS, virtual reserve provider, and Scarcity pricing situations

Currently there are a number of manual interventions aligned to the ex-post final pricing schedule which revise certain pricing outcomes prior to interim price publication. These situations are defined in the Code and in the case of the HSWPS, virtual reserve provider and scarcity pricing situation the steps to resolve the situation are also detailed. The Code requires the SO to provide revised data which resolves infeasibility situations.

Briefly these situations are:

HSWPS – a GXP price has been calculated which is more than 5 times the highest marginal generation offer and a binding transmission constraint exists. A relaxation factor is then applied to the limit of the binding transmission constraint(s).

Virtual reserve provider – following resolution of an IR deficit specified 'dummy' IR offers are added to the final pricing solution by the pricing manager to cap IR prices and the potential impact on energy prices arising from co-optimisation.

Scarcity pricing situation – if the SO instructs involuntary load shedding the affected trading periods may be subject to the scarcity pricing provisions within the Code. Those provisions set a floor and cap for prices reflective of load having been shed due to a shortfall of capacity.

Infeasibility situations – occur when the solver cannot find a solution using the offers submitted and the constraints which are required to be met. Generally, this is a 'mismatch' between the solver being required to serve load (metered values) and an inability to do so (lack of transmission ability). Most commonly this arises due to the modelling of outages in discrete trading periods and the recording of metered load dynamically.

As detailed in section 4.1.1,stepped scarcity bid prices would be applied to all load for which no price information has been submitted by the purchaser. The addition of scarcity bids, and ability for the solver to clear scarcity bids, addresses the justification for these interventions in final pricing, with the exception of infeasibility situations. Consequently, the specific price moderation effects of the HSWPS, scarcity pricing situation, and virtual reserve provider do not need to be replicated in the RTP design.

HSWPS and Virtual Reserve Provider provisions exist to ensure final prices are not unduly affected by the current high CVP prices when the solution is highly sensitive to small changes in input data. Or, in the case of Scarcity Pricing Situations to ensure the final price is both sufficiently high to reflect the shortage in capacity and that the price is not unduly high.

Transpower observes the current scarcity pricing provisions contain a cumulative price cap; if prices have been high enough for long enough scarcity pricing ceases to be applied. Consideration should be given to this market design element with regard to the implementation of RTP.

Scarcity bids would be cleared instead of CVPs when a solution is infeasible due to their lower price. The physical mismatch, and potential load shed, will still occur; the deficit being met by cleared scarcity bids instead of cleared CVP. Infeasibility situations arising from outages would be addressed as described in Section 4.2.5.

How the CE IR CVP need to be amended to compliment the scarcity bid prices and produce results consistent with the desired outcome has been detailed in section 4.1.2.

4.2.4. Co-optimisation of IL and DD

Some IL offers directly relate to a bid load; if the load is not being consumed then the IL is not available and vice versa. With all load having a price (bid or scarcity bids) and the inclusion of DD in the dispatch schedule it would be possible to co-optimise IL and load. Currently this is not possible because DD is dispatched from the NRSS and IL from the RTD schedule. The task of ensuring complimentary scheduling of IL offers and load consumption sits with the trading participants.

Co-optimisation of IL and load would mean the solver makes the scheduling decisions; load bids[24] in excess of their purchase price would be scheduled in order to access the associated IL if this is the lowest cost solution. Co-optimisation of IL and load can only take place at single locations independently; i.e. the location defines the relationship between the 2 quantities. Purchasers would be kept whole financially through constrained payments for any load consumed at a price in excess of their bid prices. Co-optimisation of IL and load is equivalent to the co-optimisation of IR and energy at generation plants.

Co-optimisation of IL and load is not necessary to implement RTP. Further there are several complications which mean the basis on which this would actually be implemented needs dedicated consideration. For instance, how would aggregated IL offers submitted at a single GXP be treated when there is not a 1:1 relationship between the two quantities at that GXP? Equally the relationship between IL and load at an industrial GXP may not be as simple as 1:1. There might be unoffered onsite generation, meaning the IL offered can be larger than the load bid.

It is also unclear how the co-optimisation of IL and load should work when the IL trader and purchasers are not the same entity? Several EDB offer IL into the IR market but are not themselves purchasers from the wholesale electricity market. Or, the IL might be traded on behalf of a purchaser by an agent who has the ability to receive IL dispatch instructions which the purchaser does not. This aspect also has implications for the calculation of constrained on payments; what should be done if the IL and load are not traded by the same participant?

For these reasons the co-optimisation of IL and DD is out of scope of the RTP project.

[24] This includes conforming GXP Load Forecast (LF) with assigned VOLL prices.

4.2.5. PRICE IMPLICATIONS OF OUTAGE MANAGEMENT

Outages of transmission equipment are scheduled on a discrete 30-minute trading period basis. In reality the assets are removed from service at a point in time during the first period in which the outage is modelled. When the outage results in a disconnection of a GXP an infeasibility will arise in the final pricing schedule. There is no way to serve the metered load as the connecting transmission assets are scheduled out of service. A manual process is invoked which resolves the infeasibility by returning the transmission assets to service in the final pricing schedule.

For reasons of practicality, transmission outages would continue to be planned and modelled on a discrete trading period basis. It is impractical to expect transmission outage start and end times could be scheduled to occur in 5-minute time intervals to align with the dispatch schedule. Modelling the outages 'before they have begun' is also necessary to build the correct SFT constraints. From a system security viewpoint, it is also preferable to have re-dispatched generation prior to the start of the outage rather than to begin rescheduling generation coincident with the start of the outage.

Equally, it is not practical to predictively alter the load input which would be used in the dispatch schedule to zero coincident with the actual start of an outage. Consequently, infeasibilities would still arise in the dispatch schedules. Post the introduction of scarcity bids to the dispatch schedule these infeasibilities would be priced at scarcity bid prices. Given there is not an associated shortage situation, pricing at scarcity bids is not an appropriate outcome.

To address this issue, it is proposed GXPs which are marked as dead or disconnected by the market system would be assigned a proxy price. This proxy price would be based on equivalent market prices. The proposal included as part of the ROM is to set the proxy price equal to a historic average of the affected GXP's location factor multiplied by the applicable reference node's price. This proposal is seen as a pragmatic solution to a difficult problem.

4.2.6. CONSTRAINED ON AND OFF

Constrained on and off payments are calculated by NZX in their role as the clearing manager. Retention of this aspect of market design is required under an RTP regime because market settlement remains on 30-minute trading periods using an average price. By definition when an average is calculated the values being averaged may have been higher or lower than the average price. Consequently, generator offers higher than the settlement price may have been dispatched and, subject to actual performance, may be due a constrained on payment.

Constrained on and off calculations would require amendment should the proposed change to allow more than 1 bid or offer to be present for a trading period go ahead (see Section 4.1.5). This is to ensure the payments made are correct and not unduly affected by any revised trades. For example, a generator whose offer for a trading period reduces from 30MW to 10MW during the trading period should not have dispatch instructions for the 'full' 10MW later in the trading period assessed against the 30MW offer.

4.2.7. MARKET SYSTEM OUTAGES

During market system outages dispatch schedule prices would not be published. During both planned and unplanned market system outages the Transpower uses back up tools for dispatch, namely the Stand Alone Dispatch (SAD) tool. By design SAD is a simplified version of the market system; the solver is identical but there are no live inputs (save for co-ordinator adjustments and SCADA, if available) and publication is limited to dispatch instructions. This is intentionally, a minimalist design allowing core functions to be performed while presenting less risk of failure from complexity, both of functionality and connectivity.

Enabling price publication from SAD does not sit with the minimalist design of SAD. The more functionality SAD has, the more opportunities there are for something to go wrong. Changes are only made to SAD which are necessary for the dispatch of the power system.

RTP design requires a price which is actionable. Actionable prices have to be visible prior to, or at the time of consumption. Publishing historical RTP prices once the market system outage has been completed does not meet this requirement.

With no RTP prices being published during market system outages and dated publication being unacceptable an alternate source of RTP prices is needed. It has been agreed to use PRSS prices as the substitute RTP price during market system outages.

There are 3 permutations to the derivation of the interim price during market system outages:

- The last dispatch price published prior to the cessation of dispatch price publication stands for the reminder of the trading period. This occurs in the trading period in which the market system outage commenced. It is equivalent to price handling when there is infrequent re-dispatch within a trading period. The interim price is the time-weighted average of the dispatch prices published.
- For trading periods where no dispatch prices are published the most recently published PRSS price for the trading period applies.
- For the trading period in which the market system outage ended the PRSS price is included in the time weighted average, along with the published dispatch prices.

Transpower notes pre-published settlement prices are not ideal. Pre-published prices allow for discrepancies to occur between bid load consumption (upon which the PRSS prices are based) and actual consumption (upon which settlement occurs).

Dispatch of the demand side during market system outages is problematic. Purchasers who are not DD participants would not receive updated price or quantity information, with which to self-dispatch themselves, from the dispatch schedule. SAD would be altered to include DD bids but not scarcity bids and non-dispatchable demand bids. A “no pricing” mode of SPD operation would be developed which only includes DD bids in the dispatch schedule and excludes all other demand side bids. This version of SPD would be the one used by SAD. It may also be released into the market system for use when there is a fault disabling publication of dispatch prices to WITS. In this instance the demand side would not have access to updated information upon which to base their self-dispatch decisions on.

4.2.8. Pricing Error Claims

The pricing error claim (PEC) aspects of the current market design would be amended for use in the RTP regime. It was considered whether the PEC provisions be removed from the Code. The outcome of a successful PEC, revised interim prices, is contrary to the goal of actionable prices. If prices are revised on a frequent basis, then the industry’s trust in price certainty would be eroded.

However, the ‘peace-of-mind’ retention of the PEC provisions provides may offset some of the concerns the industry may have concerning RTP. Further, retention of the PEC provisions may be required to address scarcity bid prices occurring when load is not shed due to the absence of a security situation.

Nevertheless, changes are required to be made to the PEC process. The party obligated to perform most of the PEC process, the pricing manager, would cease to exist[25]. It has been decided the Authority would assume the PEC process functions currently performed by the pricing manager. Dispatch price recalculations would be performed using the Authority's vSPD solver[26]. Doing so avoids the costs which would otherwise be required to alter the market system to rerun dispatch schedules.

The Authority is considering adding a minimum market impact to the PEC claim. A move designed to limit the number of PEC received given the need for price certainty to achieve the benefits expected of RTP. Care and consideration would also need to be taken to define what actually constitutes a price error under RTP? The current PEC process hangs on a data error having occurred. By definition the inputs to an ex-ante schedule are harder to define than an ex-post schedule, making it harder to define what constitutes a data error. As an example, the GXP load in the ex-post schedule is metered load; an error being any deviation from the values prescribed in the Code. For the dispatch schedule the GXP load is a forecast value, how could an error in an estimation be defined?

A possible mitigation would be to hybridise the PEC and compare dispatch schedule results with a dispatch schedule amended to 'actual' values[27]. Again this would have to be carefully considered, to what extent would ex-ante inputs be changed to ex-post? Would it be limited to the input data considered to directly affect the source of the PEC or are all values changed? The latter being the current ex-post final pricing schedule, i.e. a wholly ex-post schedule. The steps to resolve a PEC are not overly prescriptive in the Code so PEC may be able to be resolved on a case-by-case basis.

It is noted there may be associated Code changes to enable market prices to be calculated using vSPD. Price publication of any revised interim prices arising from an upheld PEC would need to mimic standard price publication functionality to ensure all end-users are unaffected.

4.2.9. BIDS

Significant changes to the way bids would be used in the dispatch schedule are proposed under RTP. These are detailed in the following paragraphs. For ease of reading the bid types are referred to by their market system codes and the table from Section 4.1.6 is repeated for quick reference.

Table 3: Bid Types

Market system bid code	Descriptor
ENDL	A DD bid. May be either dispatchable or non-dispatchable on a trading period by trading period basis. Bid is for total quantity.
ENNC	A non-dispatchable bid at a non-conforming GXP. Bid is for total quantity.
ENDF	A difference bid; a variation against normal in response to price at a conforming GXP. Non-dispatchable

[25] See section 4.4.3

[26] Assuming the industry are happy for interim prices to be calculated in this way.

[27] This schedule would bear a strong resemblance to the current schedule of real time prices.

ENXX	A ‘dispatch lite’ bid for total quantity at a non-conforming GXP. Dispatchable.
ENZZ	A ‘dispatch lite’ difference bid at a conforming GXP. Dispatchable.

Currently only the total load contained within both ENDL and ENNC bids are included in the dispatch schedule; no load is dispatched from the dispatch schedule. ENDF bids, along with the price information attached to the ENDL bids and ENNC bids are omitted from the dispatch schedule.

Under RTP ENDL, ENXX, and ENZZ bids, inclusive of price and quantity, would be included in the dispatch schedule. ENNC and ENDF bids would be discarded. The load represented by an ENNC bid would be derived from actual load, like a conforming GXP, and would be assigned scarcity bid prices. These changes mean all load has an associated price for scheduling in the dispatch schedule.

DD instructions would be issued from the dispatch schedule, and not the preceding NRSS as they are now. The impacts of RTP on DD is detailed in more depth in section **3.5.1**.

Opting out of dispatch

The current design of DD allows a DD participant to opt out of being dispatchable on a trading period by trading period basis. Observations of DD in current use suggest this functionality is used; there are times when a load participant wishes to be fully in control of their consumption patterns.

It is suggested non-dispatchable ENDL bids are treated as ENNC bids in the dispatch schedule. This is consistent with the current handling.

ENNC bids

The source of the actual load which replaces the bid quantity for ENNC bids would be the SO’s SDV data process within the market system. SDV assesses sampled SCADA data against quality and threshold criteria. Data which fails validation is then replaced by the next best quality data following a preordained hierarchy. The best quality data at the end of the validation process would then be substituted for the bid quantity in the ENNC bids at each applicable GXP. The scarcity bid prices would be assigned against the substituted quantity.

A variation to the RTP design was separately costed where the GO’s ION meter data would be the preferred primary data source. SCADA data would then be the second highest priority within the SDV processing; with all of the other alternate sources moving one level lower down the quality hierarchy. See section 0.

Dispatch lite

‘Dispatch lite’ bids would be ‘self-dispatching’ i.e. the purchaser does not receive a formal dispatch instruction from the SO. Instead price and quantity information from the dispatch schedule would be available enabling self-dispatch. It is expected this information would be available on WITS and via the EDF 3 platform, never constituting a formal dispatch instruction.

It has been proposed ‘dispatch-lite’ participants would acknowledge whether or not they are actually going to follow their scheduled quantities. Upon receipt of a ‘no’, the associated bid would be excluded from the dispatch schedule for the remainder of the trading period. As an alternative, the SO proposes the ability to re-bid within a trading period is used instead. If a purchaser chooses not follow their current scheduled quantity, they submit a revised bid which aligns with their consumption intentions. This alternative avoids the costs associated with building a 'dispatch-lite' acknowledgement capability. A submitter of an ENXX or ENZZ bid would replace it with an updated ENNC or ENDF bid respectively. These would then be excluded from the dispatch schedule and the load input derived consistently with all other non-dispatchable load.

The voluntary nature of 'self-dispatch' is allied to an ineligibility to receive constrained on and constrained off payments.

Market implications

Transpower notes the market implications of the inclusion of 'dispatch lite' is the ability for prices to be formed on trades which are not subject to dispatch and the associated compliance aspects. The Authority and industry needs to carefully consider the implications of this.

A related observation is the compliance monitoring of bids becomes increasingly important once they are included in the dispatch schedule.

Non-conforming GXP

The inability of a central forecaster to predict the consumption at their location with sufficient accuracy results in purchasers at non-conforming GXP being required to bid the forecast consumption. In real-time this bid quantity would be replaced by an actual value derived in the same way as at a conforming GXP. This change would result in a more accurate distribution of load in the dispatch schedule. Further, this change works with either a top-down or bottom-up dispatch schedule load forecast methodology. The proposed treatment of ENNC bids is consistent with their current treatment in final pricing, all bid information is discarded and metered values are used instead.

Note the substitution of bid quantities with an actual value would take place at the GXP level not the purchaser level. The categorisation of GXP as non-conforming happens at the GXP level. All purchasers at non-conforming GXP are required to submit ENNC bids. To substitute at the purchaser level would require a commensurate actual load value. In most cases this is not available, the actual load value is at the GXP level.

Bidding above scarcity bids

If a DD or 'dispatch lite' participant wishes to consume electricity at prices in excess of scarcity bid prices they can submit bids which reflect this desire. Bids only cease to be scheduled if the cost of supply exceeds their bid price. In this situation the purchaser needs to understand their bids may set dispatch prices at the prices contained in their bid.

Optimal demand side participation

When discussing demand side bidding and their treatment in the schedules it is worth noting referencing the industry prior to the introduction of the DSBF market initiative in 2012. Prior to DSBF all purchasers were required to bid their load. These bids were the load input to the Pre-Dispatch Schedule (PDS). The global obligation to bid and the poor outcomes delivered by inaccurate bids were the key driver behind the DSBF initiative which removed compulsory bidding except at non-conforming GXP.

However, having a totally reactionary demand side is not without its own issues. The pricing phenomena often referred to as a 'saw-tooth' may occur. Saw-tooth pricing is observed when the cause and effect on price alternate on a cyclical basis. In the case of RTP this could be the demand side reacting to a high price by reducing load. The resultant low price drives a load increase, which in turn produces a high price etc. The more load which signals price sensitivity in the schedule the less likely saw-tooth pricing is to occur.

Questions could also be asked about the efficiency of the RTP price if most or all load has no price information associated with it. The resultant lack of coordinated price discovery balancing the supply and demand side viz actual intentions could be described as inefficient; some actors in the market may have misjudged and regret their decisions. Note the gross pool nature of the New Zealand electricity market means this is a latent risk unless a load is dispatched and therefore receives some protection via constrained payments.

The proposed RTP design requires all of the demand side has a price, without the introduction of scarcity bids alternative solutions to the issues of infeasibility situations, HSWPS, and scarcity pricing would need to be found. The question therefore is how much of the load is bid at prices other than scarcity bids. Settling on scarcity bids and having no other demand side price signalling in the schedules does not seem optimal. Purchasers could not signal their intent to withdraw load prior to scarcity bids being struck if they weren't able to submit bids. However, if bids submitted for such a purpose cleared but were not subject to dispatch compliance because they were voluntary then all which may have been achieved is reduction in price with no actual demand response.

The implications for the SO of the bid changes are discussed in depth in section 3.3.

4.3. SCHEDULES

To implement RTP changes would be made to schedules other than the dispatch schedule.

4.3.1. FORECAST SCHEDULES

In order to provide consistent price signalling changes made to the dispatch schedule which must also be made to the forecast schedules (WDS, NRSL/S, and PRSL/S). Input changes would be made to these schedules to include scarcity bids, and the revised CE IR CVP (see sections 4.1.1 and 4.1.2). Forecast schedules would also include any revised bid or offer for the first trading period of the schedule if such a trade is submitted prior to the schedule commencing (see section 4.1.5).

5-minute forecast schedule

It is acknowledged there would be differences between the average of dispatch prices and forecast prices. These differences would arise because of the non-linear relationship between load and price. Consequently, averaging the prices arising from multiple load values will give a different outcome to calculating the price using the average of the load values.

A possible mitigation to this was raised during the TAS60 workshops; create a PRS type forecast schedule which solves for 5-minute trading periods. The intention being to show possible dispatch prices and the spread of dispatch prices within a trading period ahead of time.

The ability to accurately forecast load in 5 minute periods in advance with sufficient accuracy to make this proposal worthwhile is questionable. Consequently, this is viewed as a possible enhancement once operational experience of RTP is gained.

SFT and RMT

The changes to run RMT and SFT from the PRS schedules (section 4.1.11) mean it is unlikely any changes to the treatment of bids are require for the forecast schedules. The treatment of bids in the dispatch schedule (section 4.2.9) aligns with the PRS design. There appears to be no justification to alter the treatment of bids in the NRS schedules; DD bids have price and quantity, nominated non-dispatch bids total quantities, and omission of difference bids. On this basis the NRS schedules would continue to forecast on the basis of no voluntary price response occurring. This may provide a useful yardstick for participants who are considering whether to comply with 'self-dispatch' quantities.

Scarcity bids

The inclusion of scarcity bids in the forecast schedules means infeasibilities and shortage situations[28] would cease to exist in forecast schedules in ways similar to those described for the dispatch schedule.

Disconnected node pricing

Outages could be handled with a proxy price assigned similar to the dispatch schedule (section 4.2.5). Industry and Authority consideration is needed to reaffirm, or advise, the price which is assigned to disconnected nodes across all schedules. Currently manual intervention to inputs reduces the presence of infeasibilities in the forecast schedules. The affected GXP's load forecast values are set to zero for the duration of planned outages. This results in a disconnected node determination rather than an infeasibility. Disconnected nodes receive an assigned price, currently this is $0/MWh.

4.3.2. Ex-post 5-minute and final pricing schedules

Both the ex-post 5-minute schedule (real time price schedule per the current Code) and the final pricing schedule would be decommissioned following the go-live of the RTP project. Once actual RTP prices used for settlement are published the need for indicative 5-minute prices ceases to exist. Equally, once all of the trading periods prior to RTP go-live have final prices published there is no need to retain the final pricing schedule functionality.

4.3.3. Constraint Adjustment Schedule

The Constraint Adjustment Schedule (CAS) was created to allow for the quick creation or adjustment of SFT constraints. The CAS solves for the current and next trading period following the NRS type. With the move to generate SFT constraints for dispatch from the PRS schedule type the CAS would be amended to be a PRS schedule.

[28] The 'pre-cursor' to a Scarcity Pricing Situation which only to the current ex-post final pricing schedule.

4.4. OTHER DESIGN CONSIDERATIONS

Design decisions and assumptions which do not fit within the three previous categories are covered here.

4.4.1. INCLUDED COSTS

Only Transpower costs are included within the ROM provided. Both other Authority service providers and industry participants would incur costs updating their tools and processes adapting to changes made by RTP. These costs may not be insignificant.

4.4.2. OTHER MARKET DEVELOPMENTS

It is assumed the SO tool initiative referred to as EDF Phase 3 (Electronic Dispatch Facility) would be complete prior to delivery of RTP. It has been further assumed the ‘self-dispatch’ demand-side participants may receive scheduling information via this platform. Included in the ROM are costs associated with delivering the ability to send the ‘self-dispatch’ information to the new EDF platform but not ‘past-that-point’ i.e. how a participant retrieves and views this information.

It is assumed the Authority’s Gate Closure Reduction initiative is delivered prior to RTP and is unchanged from the design as it currently stands. The Gate Closure project is scheduled for deployment in Q4 2016/17.

The impacts of Authority initiatives which are not yet confirmed but may be implemented between now and RTP have been assumed to be nil. Any such project would have to be assessed for the impacts on RTP and vice versa. The programme approach used by the Authority and Transpower mitigates this risk.

4.4.3. SERVICE PROVIDERS

Impacts on the other Authority service providers have been included as they relate to assumptions made to enable completion of the ROM. For completeness comment is also made about the impacts RTP is expected to have on the Grid Owner (GO).

Pricing Manager

The pricing manager role is assumed to cease to exist. The functions currently performed by the pricing manager being either replaced, no longer necessary, or reassigned. RTP replaces the need for the final pricing schedule. The manual processes associated with the final pricing schedule are unsuitable for use in RTP and have been addressed through alternate means in the RTP design. Interim and final price calculation and publication obligations are proposed to be assigned to the clearing manager and pricing error claims would become the responsibility of the Authority.

As noted previously Transpower recommends the retention of the data currently published by the pricing manager which is not directly replaced by an RTP data publication; for instance, the daily final pricing metering data. In some cases, allowance needs to made for the differing production methodologies between final pricing and RTP means there may not be directly equivalent data[29].

WITS Provider

It is proposed to publish a larger dataset from the dispatch schedule than is currently. These and any other RTP associated publication changes would need to be facilitated by the WITS provider.

WITS has very high availability rates, however an RTP regime may require an increase in redundancy and resiliency of WITS. Should this be required the justification would be derived from the benefit in 'constant' publication of actionable prices.

Clearing Manager

It has been proposed the clearing manager be the party responsible in the Code for the calculation (following the methodology prescribed in the Code) and the publication of interim prices. They would also be the party responsible for:

- the publication of final prices once the period for a PEC has expired, and
- the publication of revised interim prices if a PEC is upheld.

The retention of 30-minute trading periods and a single settlement price for each trading period means any additional impacts on the clearing manager are likely to be minimal.

FTR Manager

The retention of 30-minute trading periods and a single settlement price for each trading period means any impact on the FTR manager is likely to be minimal.

Reconciliation Manager

The retention of 30-minute trading periods for settlement means there are not expected to be any impacts on the reconciliation manager.

Grid Owner

Currently the GO is required to provide GXP metering for the previous trading day to the pricing manager before 07:30 for use in the final pricing schedule. While this data is no longer needed for the purposes of final pricing it is unclear whether a publication requirement would continue to exist and if so what the timeframe for data provision would be?

If re-offering for the current trading period is included in the implemented RTP regime (see section 4.1.5) the GO would likely be subject to the obligations requiring reoffers to reflect asset capability for the current trading period.

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[29] For example, averaging results from the dispatch schedule may lose the inter-relationship between datasets when it is not a linear relationship.

5. Initial Transpower Stakeholder Requirements

Initial stakeholder requirements to update Transpower systems and processes have been developed based on key decisions and assumptions. The key decisions and assumptions were validated with the Authority and consideration was made of the expected impact of introducing a RTP service would have across all industry sectors. The adopted approach was to inform the next industry consultation phase and assist with developing the ROM costing for solution development scope included in this TAS60 report.

5.1. Initial Transpower Stakeholder Requirement Process

The key steps in the process were;

- Identify key Transpower stakeholder requirements.
- Define workshop approach and topics.
- Requirements workshops - A series of 8 workshops were held to capture all aspects of the proposed solution as it related to Transpower's tools, processes, and interactions with the industry. Attendees at these workshops primarily consisted of the core Transpower RTP project team.
- Document and review Transpower stakeholder requirements.

5.2. Initial Transpower Stakeholder Requirement Outputs

The initial Transpower stakeholder requirements identified those capabilities that would require modification in order that the system operator RTP business services could be implemented to support the Authority RTP objectives. The scope was to identify and review Transpower capabilities in sufficient detail to inform costs for changes while identifying interfaces and external systems that may also require modification which have related cost implications for the authority to determine.

The initial Transpower stakeholder requirements established changes to capability used in all time frames applicable to the RTP service; inputs, processing and output dependencies were reviewed to establish changes required. Statements of business needs were established to provide a baseline of expected capability changes to be incorporated into the RTP business service solution. These statements of business needs are included in the discussion body of this report which provides a summary of the conceptual attributes of the RTP service to be delivered.

6. High Level Technical Assessment

This section details the high level technical assessment performed on the proposed RTP solution and also includes the proposed delivery approach. The focus is on the specific implementation aspects that contribute the most to effort and cost.

The purpose of the technical assessment is to provide the Authority with an understanding of the scale of effort required to deliver the project. This assessment is also the primary feed into creating a ROM ball-park estimate during the "Design Market Initiative" phase to inform a cost benefit analysis.

6.1. Assessment

6.1.1. Project Approach

To provide a technical assessment of the RTP solution, the project team based the scope on the initial Transpower stakeholder requirements. A series of requirements review and design workshops were held to provide this assessment and prepare the ROM estimate (detailed in section 7). These workshops were comprised of system operator and IST staff who had previously contributed to the initial Transpower stakeholder requirements.

The assessment has been prepared using expert judgement and a number of requirements established after validating design decisions and assumptions from the Real Time Pricing Option Analysis report with the Authority (see section 4).

The assessment looked at the options for delivery and determined that a four stage project with 4 implementations (which includes a decommission phase) would, based on current knowledge be a significantly lower risk approach to delivery as opposed to a single implementation. A single stage development and commissioning was also considered but rejected due to the high volume of change being introduced in a single system release.

6.1.2. Investigation Phase

The investigation phase of the project is expected to take 3 months. This would require a review and update of the Transpower stakeholder requirements gathered in the earlier TASC phase. The remainder of the investigation phase would be focused on the development of the SODA (Solution Options and Design Approach) and an initial business case.

6.1.3. Delivery Phase

At the start of the delivery phase, solution requirements and a high level design for the project would be developed. Following the high level design, a four stage delivery approach is planned and is the basis for this estimate. The purpose of this staged approach is to break the project up in to manageable pieces with an implementation at the end of each stage. The project stages would also overlap, so that the team can transition to subsequent stages on completion of their stage tasks.

The first three stages update functionality required to support RTP with RTP commissioning at the completion of stage 3. The final stage removes superfluous functionality and completes decommissioning.

Overview of Functional Updates in each stage

Stage 1 – Scarcity bids / Demand Clearing

Key changes:

- Changes to support scarcity bid based clearing of conforming load. It is assumed that scarcity bids clearing can be deployed in advance of RTP but effectively turned off by configuring suitably high scarcity bid prices.
- Make Display and Business logic changes to support load shed and restore allocations based on scarcity bid outcomes.
- Changes to configurably allow for economic clearing of ENDL, ENXX and ENZZ in RTD and non-NRS forward schedules.
- Changes involving adjustment of ENNC bids based on current SDV value (similar to TAS62 Wind Generator Offers proposal).
- Changes to configurably allow RTD conforming load base to be derived from SDV actual GXP values instead of IPS.
- MOI enhancements to support change to clearing all demand types in RTD.
- Enhanced/modified automation of NCC notices/notifications to support scarcity bid based Grid Emergency Notices.

This stage involves changes to: SPD, MDB, MOI, ETS, SAD.

Stage 2 – Load Dispatch / ESB Publication

Key changes:

- Changes to support dispatch of scarcity bids load shed and restoration to NGOCs from RTD.
- Changes to support "notify" dispatch of ENDF and ENNC loads from RTD.
- Changes to tie RTD publication to dispatch action (Send All) rather than case approval.
- Expand published data set for RTD and forward schedules, and make improvements to publication interface design.

This stage involves changes to: ESB, MDB, SCADA, ICCP, MOI, SAD.

Stage 3 – RTP

This stage would complete updates required and commission RTP.

Key changes:

- Add SPD post-processing logic to assign administrative prices to disconnected nodes, for RTD and forward schedules.
- Add new conditions to Post-Schedule Check (PSC) logic for RTD and forward schedules.
- Changes to support dispatch of ENDL from RTD.

- Changes to calculate trading period interim average prices and display within dispatch tools, for NCC situational awareness.
- Changes to derive arc flow data values (needed for transmission pricing) from published RTD and/or PRS cases rather than Final Pricing.
- Changes to provide a "no pricing" SPD execution mode for use during RTD price publication outages (while on SAD or otherwise) to remove the price responsiveness of load that would normally respond to published prices.
- Changes to SAD to support RTP.
- Changes to enable transfer/storage of trading period final prices from NZX.
- Changes to GSS interface and processing to support RTP.
- Modify FP to ensure that current functionality is retained with RTP changes in place – needed to manage transitional period.
- Changes to TTSE (Genco Tutor and DTS) to support load dispatch simulation.

Note: in addition to the key changes identified, this phase includes a comparatively high number of minor and medium changes to support go live of RTP.

This stage involves changes to: SPD, MDB, MOI, ESB, SAD, ETS, DW, GSS, TTSE

Stage 4 – Decommissioning

Key changes:

- Decommissioning of FP and RTP schedule types - removal of cases, case export views, workflow, publication, MOI displays.
- Removal of numerous MDB processes tied to FP and RTP schedule data.

This stage involves changes to: MDB, MOI, ESB, SAD, ETS, DW

6.1.4. DEPENDENCIES

Key dependencies for the RTP delivery project;

- Completion of industry consultation.
- Approval of the business case and release of budget.
- EDF Phase 3 is a pre-requisite for adding load dispatch capability, so must go live before the start of Stage 2.
- Delivery of third party components of the market system.
- Successful completion of industry user acceptance testing.

The least ‘controllable’ of these dependencies is the completion of industry consultation. Until industry consultation successfully concludes the RTP design, and project itself, remains incomplete. Any significant design changes arising from industry consultation would have to be assessed for their impact to the ROM, delivery timeframe, and operational concerns provided in this TASC report.

6.1.5. Systems Impacted

Most key systems and components relevant to the market system are impacted by RTP. This is illustrated in Figure 2. The red colouring indicating the market system components impacted by RTP.

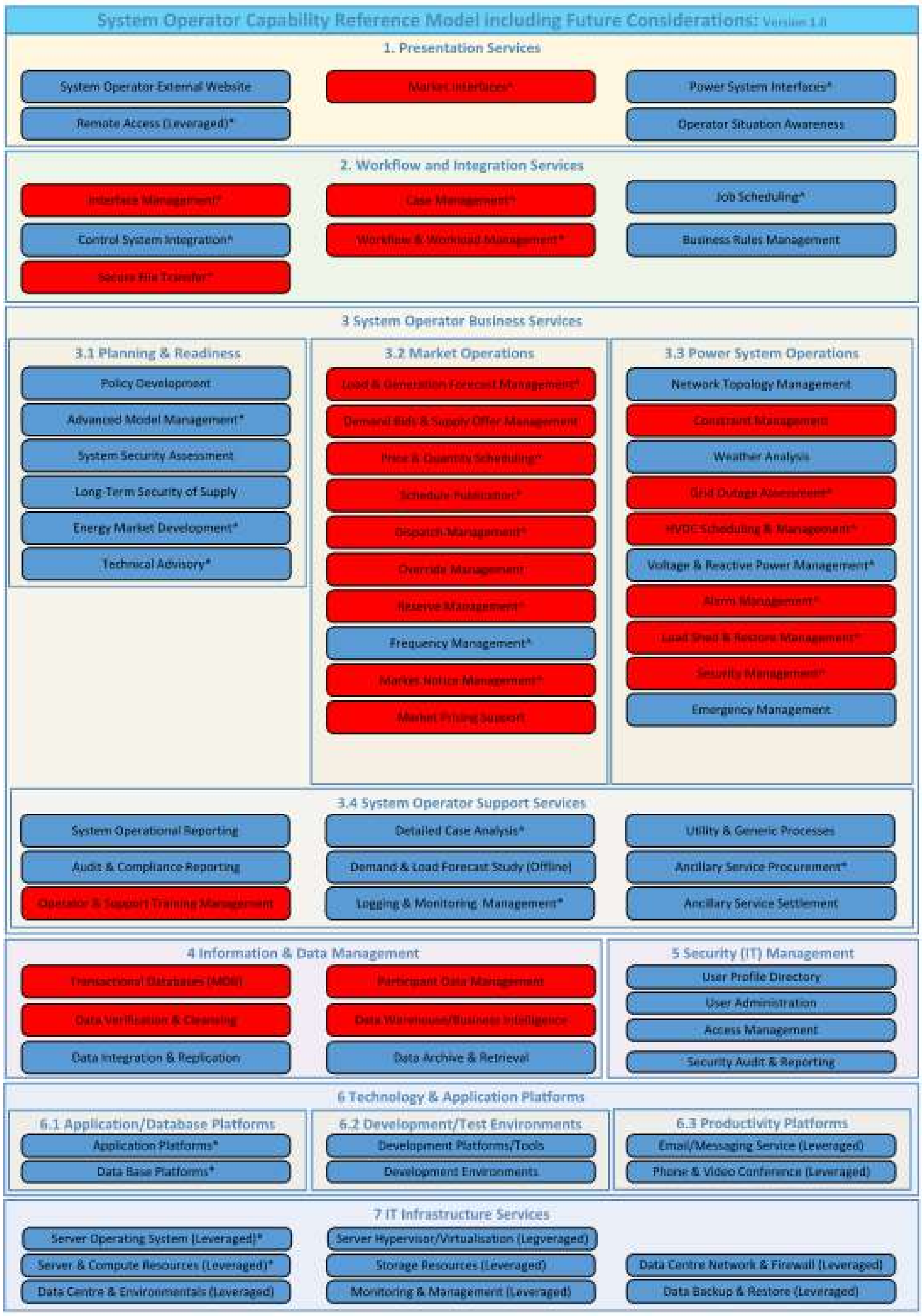

Figure 2 - impacted market system capabilities

Specifically, those impacted market system components noted by the team at the ROM session were:

Table 4: Systems Impacted

Market System Components Impacted
SPD
MDB
MOI
ETS
SAD
ESB
SCADA
ICCP
GSS
TTSE
ETS
DW

No material changes have been identified for RMT or SFT and it is assumed these would not be impacted. The project is considered high risk as the majority of market system components (as listed above) would be subject to change.

7. Rough Order of Magnitude (ROM) Cost and Timeline

This is the most complex and far reaching ROM the system operator has undertaken and the level of change is the greatest change to the market tools since their original deployment. The RTP implementation is highly complex and touches most components of the market system. Further it is expected to last for four years.

The ROM cost estimate is split into IPLC aligned phases where the next phase includes completion of Transpower stakeholder requirements and development of detailed

The work which has been done under TASC060 has provided greater certainty around the requirements and has reduced the amount of work required in the investigation phase. It has also provided an opportunity to look at how we might deliver the work. This has resulted in the decision to deliver RTP in a phased approach.

Costs and timeframes are provided as ranges representing the existing level of uncertainty.

Table 5: ROM Costs and Timeframes

Phase Name	Phase Description	Phase ROM Cost Estimate	Phase Duration Estimate
Develop Solution Approach	Update and finalise Transpower stakeholder requirements and undertake technical and operational analysis.	$250k to $300k Expected value $260k	3 months
Initiate and Deliver Project	Complete solution requirements, design, build, test and deploy RTP solution.	$7.3m to $10.7m Expected value $8.6m	32 - 37 months to commission[30]
Other service provider development	TBD	TBD	TBD
Industry development	TBD	TBD	TBD

This indicative timeline takes into consideration Transpower's planned view for delivering an annual capital programme of $2.5m for the Authority together with our System Operator Service Provider Agreement (SOSPA) fixed fee programme. The impacts of potential resource competition from other work driven by the Authority has not been considered.

[30] In addition, there is a decommissioning phase which is expected to last 6 months.

7.1. INDIVIDUALLY ASSESSED SCOPE VARIATIONS

The following table includes additional items that are non-core for RTP but are considered optional for the RTP delivery.

Table 6: ROM Scope Variations and Costs

Scope Variant	Change scope and assumptions	Impacted component(s)	Approximate size	Technical Risk level
Changes to support electronic update to bids and offers within current trading period	• Add automated re-run of CAS when short notice bid/offer changes received • MOI changes to provide situational awareness of short notice bid changes similar to existing for short notice offer changes • Assumption that no significant changes required for secure operation beyond those provide by the Gate Closure project.	MOI, MDB	$25k-$50k	Low
Changes to support use of ION metered load data in place of SDV	• Modify SDV logic to include ION meter data when available, otherwise fall back on existing SCADA sources • Assumption that ION data is available for all the same measurement points as SCADA values and in equivalent formats and therefore no SCADA changes required	Some combination of ESB, EDE, MOI and MDB	$120k-$180k	High
Changes to support "notify" dispatch of scarcity bids load shed and restoration *to EDBs* from RTD	• Assumption that each new EDF site does not require a dedicated secure connection and that secure communication over the internet would provide sufficient security and reliability. (Note: existing energy and reserve dispatch sites have dedicated network connections) • Estimated to require approximately 4 weeks of additional internal development and 4 weeks additional testing, plus approx. 2-3 weeks' coordination time per new EDF site	MDB, MOI, ESB	$110k-$150k plus additional cost per site (not estimated)	High

7.2. Complexity and Risk

During the development of the Real Time Pricing Option Analysis report it was recognised that RTP is a significant initiative for both Transpower and the Authority. In order to establish an appropriate risk management approach, it was determined that a clear and shared understanding of project complexity and risk was essential.

Accordingly, a Complexity and Risk workshop was held to assess complexity and define a risk management approach.

7.2.1. Complexity and Risk Workshop

To understand project complexity, a third party (Ascendo) was engaged to facilitate a joint Transpower and Authority workshop based on the Helmsman Complexity Model.

The objectives of this workshop were:

- To review the RTP project complexity – assess the level of project uncertainty, ambiguity and associated risks.
- To review the process for successfully managing project complexity.
- To provide a summary of key points of the Real Time Pricing (RTP) initiative, its key drivers and proposed benefits.

The workshop also served as a useful opportunity to ensure that both the Authority and Transpower were aligned on the project and its key challenges.

Key Findings

The workshop resulted in a highly interactive discussion with good engagement and debate. Key conclusions included:

- Real Time Pricing is strategic for both the Authority and Transpower and has significant industry interest.
- The project represents a significant and challenging undertaking which would need a reasonable level of change in the industry to accommodate the new real time pricing capability.
- The project is at the higher end of the complexity range in comparison to other industry initiatives, but is not the most complex undertaking to date.
- Confidence is reasonably high in terms of successful project delivery, noting that the change management element of the project would be significant.
- Risk management disciplines should focus on the contextual and social factors of the project in the first instance.
- The appropriate project controls and capability would be required to counter the complexity.

8. CODE REVIEW

The implications for the Code of a move to RTP is significant; changes are required in multiple parts of the Code. The volume of change, in particular to Part 13, resulted in a separate TAS agreement (TAS 63) specifically dealing with the Code changes required for RTP. Under TAS 63 Transpower provided comment on and assistance to the drafting of proposed Code amendments which will form part of the Authority's consultation paper.

As pre-cursor to TAS 63 Transpower was asked for comment on the scope of the Code changes required to implement RTP under TAS 60. The work performed under TAS 63 built on and superseded that performed in TAS 60. The relevant process followed and results of the TAS 60 Code review are detailed in this section.

8.1. INTRODUCTION

The system operator believes that in order to achieve optimum efficiency any changes to wholesale market pricing regulations should enable the technical design of the new regime. It follows that at this stage in the project development a regulatory framework is established that informs the forthcoming Code amendment proposal. This section describes the system operator's high-level recommendations for regulatory changes and presents an analysis of the existing Code to gauge the extent of the required changes.

8.1.1. INTERACTION WITH REVIEW OF WHOLESALE TRADING ARRANGEMENTS (TAS 61)

At the same time as this investigation, the system operator was engaged by the Authority to review the Wholesale Trading Arrangements as described in Part 13 of the Code. While there is significant overlap between the two reviews, the scope of this investigation focused specifically on changes required to the Code as a result of real-time pricing. The wholesale trading arrangements review took a more high-level view, recognizing that RTP and other projects would be making significant functional changes to the Code, and recommended that these changes are made with the principles outlined in that report in mind.

8.2. METHODOLOGY

The primary requirement of the project is to deliver a cost estimate for changes to the market system in order to enable a wholesale market utilising real-time prices. In order to achieve this the project team has worked with the Authority to establish a high-level functional design of the new pricing regime, which when interpreted as Transpower stakeholder requirements, defines the scope of the software changes required. This high-level technical design also informs how the regulatory framework might authorise the real-time pricing regime as it incorporates the anticipated policies for the regime which define the market rules.

Understanding the intended end point allows critical review of the existing Code provisions. This analysis:

- Identifies whether each Code provision requires a review (Yes, No, Maybe).
- Briefly assesses the extent of the changes required (Minor, Major, Revoke).
- Identifies whether the changes are likely to be impacted by other projects.

A summary of these findings are presented below.

8.3. SUMMARY OF CHANGES

Table 7 summarises the changes required to Parts 8 and 13 of the Code. Overall, real time pricing represents the largest regulatory change to the wholesale market since its inception. Approximately 25% of clauses in Part 13 require at least minor review. In addition, approximately 20% of clauses in Part 13 would be revoked, mainly relating to treatment of provisional prices and the current ex-post real time pricing schedule. The effect on some provisions such as treatment of conforming / non-conforming GXPs, grid owner offer requirements and the Must-Run Auction are more difficult to evaluate.

Table 7: Summary of Code changes required for Real Time Pricing

Section	Code clauses	Requires Review?	Extent of change	Reason
(Part 8) Emergencies	Sch 8.3, T.C. B	Yes	Minor	Revoke requirements for island shortage situation notice
Bids and Offers (Energy)	13.4 - 13.27	Yes	Moderate	Review Dispatchable Demand provisions; possible changes to offer format
Grid Exit Points	13.27A - K, 13.28	No		
Information from Grid Owners	13.29 - 13.36	No		
Offers (Instantaneous Reserve)	13.37 - 13.55A	No		
Scheduling	13.56 - 13.67	Yes	Minor	Ensure accuracy of forecast prices
Dispatch	**13.69A - 13.86**	**Yes**	**Major**	**Ensure sufficient for calculating settlement price inputs**
Real time prices	**13.88 - 13.96**	**Yes**	**Major**	**Revoke existing ex-post RTP provisions, repurpose for ex-ante**
Grid emergencies	13.97 - 13.101	No		
Publishing and reporting	13.102 - 13.106	Maybe	Minor	Consider performance reporting requirements
Must-run dispatch auction	13.107 - 13.130	No		
Pricing calculation and provisional prices	**13.131 - 13.166A**	**Yes**	**Major**	**Revoke provisional pricing, insert requirements for automatic resolution of infeasibilities and scarcity situations**
Interim and final prices, Pricing Errors	13.167 - 13.191	Yes	Minor	Review restrictions on pricing errors
Calculation of constrained amounts	13.192 - 13.212A	Maybe		Out of scope for SO consideration
Pricing Manager reporting	13.213 - 13.216	Maybe		Out of scope for SO consideration
Hedge arrangement disclosure	13.217 - 13.236	Maybe		Out of scope for SO consideration
Spot price risk disclosure	13.236A - I	Maybe		Out of scope for SO consideration
Financial Transmission Rights	13.237 - 13.255	Maybe		Out of scope for SO consideration
Schedule 13.3		**Yes**	**Major**	**Review dispatch schedule inputs, revoke ex-post schedule inputs**
Other schedules		Yes	Minor	Changes to offers; Dispatchable Demand provisions; Revoke scarcity pricing calculations; Redefine CVPs;

8.4. KEY FINDINGS

The output of the Code review carried out under TAS 60 was provided in detail to the Authority and is summarised here.

8.4.1. REDEFINE FINAL PRICES

Definitions for interim prices and interim reserve prices would need to reflect the RTP method of calculation. This would require inclusion of dispatch prices and the averaging methodology within the Code. Further, it would also require inclusion of the alternate sources of dispatch prices when those from the dispatch schedule are unavailable (PRSS see sections 3.1 and 4.2.7).

8.4.2. VERIFY INPUTS TO THE DISPATCH SCHEDULE

Currently the clauses detailing the inputs to the dispatch schedule are not as prescriptive within the Code as those covering the existing final pricing schedule. Changes to the provisions covering the dispatch schedule inputs should be made to give certainty to participants over the calculation of dispatch prices. Equally care must be given to ensure provision of security is not compromised by these changes.

8.4.3. REVOKE REMAINING CLAUSES DETAILING EX-POST REAL TIME PRICE SCHEDULE AND FINAL PRICING SCHEDULES

The introduction of RTP makes the current final pricing and real-time price schedules (per the Code) redundant. A significant section of Part 13 of the Code exists to define these schedules and their associated processes. Some of these provisions require retention in altered forms whilst others can be revoked.

8.4.4. REVIEW REMAINING PROVISIONS INCLUDING COMPLIANCE, MONITORING AND PERFORMANCE REQUIREMENTS

The inclusion of economic load shedding within the RTP design requires the provisions for participants' bids and demand management dispatch instructions to be thoroughly and clearly clarified. This may stretch to include EDBs.

The industry's expectations (including those of the Authority and system operator) for changes to the current compliance, monitoring and performance regimes should be captured in new Code provisions.

Appendix 1: DECISIONS AND ASSUMPTIONS REGISTER

ID#	Design Parameter	Description	Effect of Item	Impact on Project	Decision or Confirmation	Rationale
1	Ramp Rate will be 5 minute	RTP is to be based on RTD (Dispatch schedule). RTD uses a 5-minute ramp rate parameter. Is this compatible/desirable? Is there a need to change the ramp rate for RTD from 5 minute?	Scope, ROM, and Code	Nil - 5-minute ramp rates for RTD/RTP retained.	Confirmed - 5-minute ramp rates are to be used.	RTP is to be based on RTD. RTD currently uses 5-minute ramp rates. Changing from 5-minute ramp rates for RTD would be a significant change with the potential for unknown operational and security implications? It would also be unclear how altered RTD ramp rates would interact with 30 min trading periods? There is insufficient justification to progress changing RTD ramp rates to another time period.
2	Complex Ramp Rates	Does the introduction of RTP necessitate or benefit from changes to the current simple ramp rates offered by generators*? I.e. ramp rates with more parameters than just a single value for each of their up and down ramping capabilities. * in accordance with the current market design.	Scope, ROM, and Code	Not considered.	Confirmed - out of scope	This is an existing issue which will be addressed separately by the Authority. It is expected this would add a significant level of complexity to the project which would be unjustifiable given it is not necessary to implement RTP.
3	Solve frequency for RTP to be the same as for dispatch	Is there a need to have dispatch prices published at regular intra-period intervals? Is there the ability to issue dispatch instructions in between those timings if such an obligation was created?	Scope, ROM, and Code	Could create backward obligation on dispatch timings and allowable behaviour. Impacts averaging methodology used for settlement. Dispatch at the start of the trading period.	Minimum: solve, dispatch, and price at the beginning of each period. Price on subsequent solutions within the trading period from which dispatch instructions are issued. Dispatch prices will hold until revised which must be aligned with new dispatch instructions.	If there isn't a need to re-dispatch there isn't an associated price change which needs to be signalled, simply there isn't anything to react to if nothing has changed. Goal of RTP is to provide actionable prices aligned to dispatch, not to control or amend the dispatch process. Price averaging methodology accounts for variability of price publication timing.
4	Price publication to WITS	Does the introduction of RTP change the current market design of price publication to WITS?	Scope, ROM, and Code	New data feed to NZX as RTD $'s are currently unpublished. Price publication to align with frequency from '3'.	Confirmed. Dispatch prices published when dispatch instructions are issued. Dispatch price overwritten on WITS when a new dispatch is issued.	WITS is the central information hub for the wholesale electricity market.

ID#	Design Parameter	Description	Effect of Item	Impact on Project	Decision or Confirmation	Rationale
5	30-minute settlement period	Does the introduction of RTP change the current 30-minute trading periods? Any change from the status quo has significant implications for multiple areas of the market design and operation.	Scope, ROM, and Code	Nil -Treated the same as in current market system, 30-minute settlement will be retained	Confirmed – 30-minute settlement periods will remain.	A change from 30-minute settlement periods is not required to implement RTP. While there may be some benefits from reducing the settlement period to allow direct alignment between price and consumption* this would be a significant change with wide ranging implications. The size and scope of those changes, when considered with those required to implement RTP, have led to the decision to retain 30-minute trading periods. A reduction in trading period duration could be a future enhancement once RTP is operationally embedded. * this relationship is blurred somewhat when volumes and prices are averaged over the 30-minute trading period.
6	Price Averaging methodology	Multiple prices may be produced per trading period. Settlement requires a single price per trading period therefore there must be an averaging process to produce the single price. Options include time, volume, or a combination of time and volume weighting to create the single settlement price. Subsequent questions are should averaging be 'live' (i.e. during the period as new RTP prices are published) or only at the completion of the 30-minute trading period, and who is responsible for calculating the average price?	Scope, ROM, and Code	New functionality, although current 5 minute prices are averaged. Potentially new data feeds if not Transpower who is doing the averaging, i.e. the volumes. Integration with market system outages, i.e. when a trading period has a mix of live data and market system outage methodology.	The Authority will cover the implications of averaging methodologies in the consultation, with recommendation of time weighted for implementation. Prices will be per GXP. ROM to be based off averaging performed by the clearing manager (NZX) and settlement prices passed back to Transpower.	RTP has 2 objectives; the price needs to represent the trading period conditions and it needs to be actionable. Time weighted is the simplest option. Other more complicated options may be 'overcooking' the solution.
6A	IR price averaging methodology	Along with energy prices multiple IR prices will be published per period. How are those averaged to a single settlement price?	Scope, ROM, and Code	Time or Volume weighted, or a combination? Are prices to be indicatively averaged during the current trading period?	The Authority will cover the implications of averaging methodologies in the consultation, with recommendation of time weighted for implementation. ROM to be based off time-weighted averaging with comment on implications of other options discussed.	RTP has 2 objectives; the price needs to represent the trading period conditions and it needs to be actionable. Time weighted is the simplest option. Other more complicated options may be 'overcooking' the solution.

ID#	Design Parameter	Description	Effect of Item	Impact on Project	Decision or Confirmation	Rationale
7	Price Averaging responsibility	Who is the party who averages the multiple RTP prices to a single price for settlement? Responsible party to provide averaged prices to WITS for publication and to the clearing manager for settlement (or incl. WITS in Code as party who does this?)	Scope, ROM, and Code	If Transpower responsible, then reliability of interfaces etc. will need to be determined. Outcome will determine the new data feeds required: Transpower to clearing manager? Load values to WITS? WITS to clearing manager (in Code)? WITS to Transpower (Transpower needs final prices)?	Decision – the clearing manager will be the party obligated under the Code to perform the price averaging calculation.	WITS may be best placed to do the averaging given their role in publication i.e. they have best visibility awareness of when price feeds have stopped and which data therefore should be used to generate both the RTP price and average price. In some ways it could be similar to the role WITS plays in the DD dispatch instruction process. However, WITS is not included sufficiently in the Code nor is it a role which aligns to a 'calculation' role; WITS is a conduit and host of trading information for the industry not a producer of information. Consequently, agreement was sought from NZX to propose the clearing manager would be the party obligated in the Code to perform the price averaging calculation. NZX agreed to the proposal.
8	Forward Schedules	Is there a need to show 5-minute intervals in forecast or scheduling time? Alignment of 5 minute prices average vs 30-minute average?	Scope, ROM, and Code	Un-costed in previous work. Would need to scope and design a forecast schedule (indeterminate type, probably PRSS?) to include 5 minute intra-period variations.	The Authority to identify option for consultation To comment on in TAS report.	Settlement will still occur on 30-minute trading periods. It is acknowledged there will be a difference between the average of dispatch prices and forecast prices based on 30-minute average values. The ability to accurately forecast the 5 minute periods in advance would also be questionable, negating the benefit of this idea. This is viewed as a possible enhancement once operational experience of RTP is gained. Consultation will cover directly.
9	Market system Outages	What prices are used during a market system outage when no RTP prices will be published?	Scope, ROM, and Code	Need agreement on what price would be used; • Either previous forecast price. • Good till cancelled RTP price - issue is change of offers with change in trading periods. • Retrospective price uploaded from SAD after an outage. • Link to forecast 5-minute schedule? (if created) Needs to consider how the average is calculated when there is a blend of RTP and market system outage occurring within the same trading period?	Use the PRSS price for market system outages if a trading period is wholly missing RTP prices. Use RTP price as 'run-on' price for averaging when a market system outage starts, i.e. the last RTP price published in a trading period applies for the remainder of the period. Use PRSS price and RTP prices to calculate the average price for a trading period when a market system outage ends.	Prices must be actionable; therefore, they cannot be published retrospectively. Transpower is wary of any changes required for SAD, it exists to be a back-up less likely to be affected by market system issues due to its simplicity. Consequently there is a need to have a published price from another source than dispatch. The Authority has recommended the PRS instead of the NRS due to prior analysis. Price source blending is required for the start and ends of market system outages to best make use of the available prices to represent the trading period. This decision also minimises costs and keeps SAD as is. NB - post implementation this may need to change based on experience or alternatively compliance may need to change if it is observed there is abuse of this process to suppress PRSS prices by deliberately under-bidding load.

ID#	Design Parameter	Description	Effect of Item	Impact on Project	Decision or Confirmation	Rationale
10	Pricing error claim process remains in place to support the Transpower RTD solution implementation	The Undesirable Trading Situation (UTS) facility must be retained. RTP prices will be published as interim to allow time for pricing error claims to be investigated and revised interim prices to be published if instructed by the Authority. Price error process is contra to actionable prices.	Scope, ROM, and Code	Could require the ability to re-run RTD. Market system is amended to allow for 'offline' RTD rerunning and republication of prices. No mechanism will exist for republication of prices other than for undesirable trading situations and pricing errors. Storage of data. Who/how would interim prices become final? Currently a manual process by pricing manager.	Decision - the Market Performance team at the Authority will process price errors and recalculate the settlement pricing using vSPD. Those prices are then passed to NZX for publication. Consequently, no associated Transpower costs for the ROM. NB - need to mention in TAS report the requirement to have settlement prices in Transpower systems and highlight potential issues with any non-standard publication route with this option.	Price errors claims and the potential revision of prices post-decision making is contra to the RTP goal of actionable prices. Certainty of price is a key attribute of actionable prices. However, the price error process is intended to be retained to give comfort to the industry as they undergo the significant change RTP brings. The current interim pricing process aligns with the ex-post pricing in operation, i.e. actions have already been taken so why not get prices correct. This logic doesn't hold for RTP as the goal is price/decision linked 1:1. Suggest question for consultation - does the interim pricing facility need to be retained? Why?
10A	Pricing manager service provider role	Does the pricing manager service provider role exist post-RTP implementation?	Scope, ROM, and Code	Tool access/functionality, Code obligations, and Code review.	The Authority to cover in consultation. Likely to be disestablished. 2 possible aspects of current role under RTP design are to be the party tasked with averaging prices and or responsibility for the price error process.	The pricing manager service provider role currently exists, primarily, to calculate and publish the ex-post final prices. Those prices won't exist under RTP. It isn't 100% clear yet whether there is an altered role for the pricing manager under RTP? An RTP pricing manager role could be tasked with averaging prices and or price error claim resolution/price republication.
11	Dispatchable Demand replaced by RTP based on 5-minute dispatch	Currently DD is dispatched from the NRSS prior to the beginning of each trading period. With the implementation of RTP does this pre-dispatch facility remain? If not what does DD look like, given the demand side must remain in the price formation as active participants, i.e. can set price rather than just react to price.	Scope, ROM, and Code	If the current scheme is disbanded this needs to removed accordingly. If new scheme is included in RTD this needs to be included in ROM and TAS etc. Or any combination thereof.	Decision - DD is to be incorporated into the RTP solution and the current scheme ceased. For Authority to cover in consultation - Bids will be included in RTD and may take different forms reflective of differing capabilities i.e. full DD and 'dispatch-lite' DD. In full DD the load would be bid and dispatched from RTD according to the price bid. 'Dispatch-lite' bid submitters would be able to elect to comply or not with dispatch instructions. Having	No-one else benefits from pre-dispatch. The origin of the current DD, uncertainty of price forecasts, is addressed by the price certainty which RTP will deliver. There still needs to be a mechanism by which loads can participate voluntarily in RTP i.e. it is unlikely mandatory DD could be rolled out nationwide.

ID#	Design Parameter	Description	Effect of Item	Impact on Project	Decision or Confirmation	Rationale
					made that decision, it would apply for the rest of the trading period. A feedback loop/heartbeat mechanism would need to be implemented to facilitate the optionality of this feature. Alternate is to require the trader updates their bid to reflect altered decision.	
12	Forecasting of load at Non-Conforming Load (NCL) GXP remains the responsibility of the connected party via bids.	A central load forecast (LF) cannot accurately predict some GXP load. Currently this responsibility sits with the purchasers and a methodology for identifying non-conforming GXPs resides within the Code. These bids are used for the forecast schedules and as the load allocation at a NCL GXP in the RTD schedule.	Scope, ROM, and Code	2 options - status quo of bids or use SDV to get the actual load. When consumption is different to bids the discrepancy is spread over the LF region. Potential issue for prices sensitive to transmission limits and for volume weighted $ averaging.	Consider implications for changing to SDV data for current BLPF for RTD schedule in TAS/ROM. Non-DD bids submitted at NCL GXP will be omitted from the RTD schedule. In their place an actual load value from SDV will be used. The scarcity bid tranches will be applied to the actual load. Forecast schedules will use the bid without modification.	The need to have actionable price signals for each GXP means the load at each GXP should be as accurate as possible. Using the bids at NCL locations may not support this goal. The use of a real-time actual value will not predict intended load changes the way a bid would. The effect of such an error will be limited until the next dispatch schedule, at which time a new real-time actual load will be used. Bid inaccuracies remain until either the bid is revised or actual load aligns with the bid; this is often longer than 5 minutes.
13	Deficit Infeasibilities / Scarcity	Scarcity bids-based CVPs, Load Shedding	Scope, ROM, and Code	Need to establish Authority approach; How are scarcity bid prices set? How is load shedding handled? Will these be cleared by constrained on/off payments in settlement? Should Energy/Reserve CVP's be treated the same? What about Deficit/Surplus CVP's? Needs an operational view and an economic view of how to address. Will there be bidding which is non-NCL/DD i.e. $ higher than scarcity bid prices to signal intent to stay on?	Decision use scarcity bids based variation as price sensitivity at each non-DD or 'dispatch-lite' GXP. Authority will advise the CE IR CVPs to use in the schedules. Expect to use scarcity pricing type bid prices, i.e. work the same as virtual provider. Infeasibilities will exist (unserved load) but the CVP's will be economic values used in the calculation of the $'s and subsequent average $'s. Dispatch will provide	To realise the benefits of RTP all load needs to have a non-supply price. To apply this equitably the non-supply prices need to be graduated to share the impact which would otherwise accrue disproportionally at certain GXP/regions. Further this design would allow for actual load shed to align with RTP prices. To maintain the industry decision of a preference for IR deficits to occur before load shed or the disbandment of IR scheduling the CE IR CVPs must be revised to trigger before scarcity bid prices. NB the potential for a FIR and a SIR deficit to occur simultaneously means the total of both the FIR and SIR CVPs must be less than the lowest scarcity bid price tranche. Failure to do so could result in physical offers remaining uncleared when load is shed.

ID#	Design Parameter	Description	Effect of Item	Impact on Project	Decision or Confirmation	Rationale
				CE IR CVPs need to be advised by Authority too.	mechanism to reduce load. Will not impact SO PPO's. Bids can be submitted which 'outrank' default CVPs or default bids i.e. load can signal willingness to stay on up to $30k/MWh and this will replace the $10k-$20k/MWh 'bids'.	
14	Pre-Solve Deviation (PSD) includes shed load	Once load is shed it will not be included in the current RTD schedule. Consequently, the RTP prices will not reflect the existence of non-supply. This is not in-line with the goals of RTP; to set prices which reflect the cost of supply and give actionable price signals.	Scope, ROM, and Code	Need to include unserved load in future RTD schedules so RTP prices deliver on their goal. NB multiple ways in which this can be achieved.	Confirmed - RTP prices need to reflect any ongoing non-supply.	RTP prices need to be actionable and reflective. Setting prices based on prices which the power system can supply when there is unserved load does not accurately reflect system conditions. Consequently, the RTP solution must include unserved load in the formation of future RTP prices until such time as that load is served.
15	Outage Infeasibilities	Outages are modelled for entire discrete trading periods. Loads are dynamic and continue to exist/restart with the actual connection status. The connection status change occurs within the trading period in which the outage is first/last modelled. Consequently, actual load will be modelled as infeasible. This would not seem to be an appropriate RTP price signal.	Scope, ROM, and Code	If acceptable -nil. If unacceptable a solution needs to be found which will not result in scarcity bid prices due to outage timings issues. Operational - any changes to the timings of outages would have a significant impact operationally. Currently the impact of an outage is included in RTD prior to its commencement, this means generation scheduling already accounts for the outage prior to it starting. Operationally this is preferable, and less risky, than waiting to adjust dispatch once the outage has physically begun.	Decision - fix prices at creation, i.e. RTP prices should not be impacted by mismatches between reality and modelling timings. For disconnected nodes post processing logic will assign an administrative or proxy price. The exact calculation of this price will be determined in the next phase; a suggestion is to use the appropriate reference price adjusted by the historical location factor. To be determined whether this will apply to unequivocally disconnected busses.	RTP prices need to be actionable and reflective. Setting prices based on a connection status mismatch between modelling and reality runs contra to this goal. Consequently, it is required to have a solution which will publish RTP prices more reflective of the actual costs of supply.

ID#	Design Parameter	Description	Effect of Item	Impact on Project	Decision or Confirmation	Rationale
16	Dead/Disconnected bus processing	This process sets a zero price for buses which have been identified as dead/disconnected in each solution. Is the current process fit for purpose for RTP?	Scope, ROM, and Code	Need to establish Authority concerns to establish an approach; Is an administrative process in final pricing required? Do we need to fix; a) when setting the price, or b) during settlement, or c) a combination of a) and b)	Post processing logic will assign an administrative or proxy price. The exact calculation of this price will be determined in next phase; suggestion is to use the appropriate reference price and adjust by historical location factor. To be determined whether this will apply to unequivocally disconnected busses. Should any zero prices remain from dead/disconnected processing they are to be excluded from the price averaging methodology. If dead for an entire half hour trading period, and zero prices remain, the zero needs to be included in averaging for determining the final price. Genuine marginal zero prices will be used in the averaging methodology, i.e. no exclusion by price, exclusion is to occur only on the identified bus status.	Prices must be actionable and reflective. Averaging zero prices which represent disconnection rather than supply costs is not reflective. Desire is to have actionable representative prices. This includes this process. The issue is when there is a mix of live and dead status within the same trading period. This would result in a mix of zero and non-zero prices, the averaging of which could give poor results in terms of the cost of supply. Potential solution is to exclude all dead/disconnected prices from averaging methodology.
17	High Spring Washers pricing situations (HSWPS)	How is the current HSWPS process impacted by RTP? What, if anything, is the replacement HSWPS mechanism for RTP?	Scope, ROM, and Code	Nil - decision means no direct impact of HSWPS on RTP project. NB existing HSWPS functionality will be impacted by the treatment of the current final pricing functionality; a separate design parameter.	Confirmed - HSWPS functionality is not required under RTP. Applying the scarcity bid based prices delivers similar outcomes and is a key design parameter of RTP. **NB -** issue raised 31/10 with Authority about the physical non-supply which will be modelled to occur when a scarcity bid based CVP is struck, i.e. will load shed need to occur when a CVP is used as a result of a HSWPS? Answer,	The HSWPS was implemented to ensure prices weren't unduly impacted by highly sensitive solutions being close to infeasible, therefore being close to the CVPs. With the move to economic CVPs this risk is mitigated. Consequently, specific HSWPS mitigations are considered unnecessary. The issue of surprise HSWPS being calculated in ex-post final pricing is also addressed; settlement prices will be derived from prices visible to participants.

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					yes, subject to any operational minima considerations (yet to be defined).	
18	Forward Schedules	Do the forward looking forecast schedules need to align with the market design changes made by RTP? E.g. scarcity bids, infeasibilities, HSWPS etc.	Scope, ROM, and Code	Requirements to apply the requisite changes to the forecast schedules to align with RTP; delivering sensible, consistent market data to participants.	Confirmed - all appropriate changes made to the market design and or solver/optimisation changes to implement RTP via the RTD schedule must also be made to the forward looking forecast schedules. NB there will be some exceptions due to the differing timeframes and inputs of each schedule type.	This is required to deliver a consistent suite of price signals to participants. In the absence of this decision RTP would be less useful and deliver less benefits.
19	HVDC Configuration	Some DC inputs are set for the half hour and some in real time for legacy reasons. This will need reviewing for any implications for RTP.	Scope, ROM, and Code	Need to review legacy use of 5 minute and 30 minute inputs for schedules. Need to review inconsistency in operating rules.	Will be addressed in the next phase of the RTP project.	The HVDC parameters will be assessed as part of the next phase of the RTP project; considering the change from a 30-minute ex-post pricing schedule to RTP pricing as appropriate. The need to reflect alignment with RMT remains but the need to reflect 30-minute ex-post settlement pricing does not.
20	Load input to the RTD schedule from SCADA/SDV	Either a method of distributing an aggregated load to the GXPs or a means of measuring load at each GXP is required. Currently load is calculated at an Island level and then split to region and then finally to GXP using BLPFs derived from SDV values.	Will work as currently implemented representing conforming load.	Obtaining ION meter data via SCADA may be improved if a new version of SCADA/EMS is implemented within the time frame of RTP project. Only for BLPFs? Apply to NCLs too instead of using bids? Link to dispatchable status of bids. SDV may be OK. A bottom-up rather than the current top-down approach is preferred. Need to include an incremental costing for this approach.	Changes to the current SDV/SCADA load inputs are in scope. Include a bottom-up load derivation option as an incremental costing option in the ROM/TAS report.	Accuracy of the load values used in the RTD schedule will be important both for setting the price and for the possibility of volume weighted averages. It is also critical for any solution from which load management/load dispatch takes place; i.e. if load is to be shed the quantities should be as accurate as possible. Under the current load calculation methodology it is possible to distort or dilute the intended actionable price signals which RTP will deliver.
21	Generation unit Samples from SCADA/SDV	Does the introduction of RTP require a change to the current SCADA/SDV process for generator unit samples?	Scope, ROM, and Code	Nil - Treated the same as in current MS	Confirmed - SCADA/SDV generator unit samples are unchanged by the implementation of RTP.	There is no need to change the current SCADA/SDV process for generator unit samples to implement RTP.

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22	Generator/Ancillary services offers	Does the treatment of participant offers change as a result of RTP? Currently these offers remain static for the current trading period with discrepancies managed by manual coordinator actions.	Scope, ROM, and Code	Include in ROM and TAS report the cost/implications of allowing revised trades to be submitted for the current trading period.	In scope - include in the ROM and TAS report.	The move to strike prices intra-period aligns with the intention to allow trades for the current trading period to be revised under criteria often referred to as bona-fide conditions. Currently this is effected through the addition of discretionary constraints to the RTD schedule by the coordinators to restrict the scheduling of affected offers to within the advised limits. Under RTP participants may wish to identify which uplift costs are associated with the use of discretion. Without this change it would be less clear which costs arose from the genuine use of discretion and those which were 'updating offers'?
23	GO asset offers	Does the treatment of GO asset offers change as a result of RTP? Currently they are treated as dynamic, i.e. can change intra-period.	Scope, ROM, and Code	Nil - Treated the same as in current MS	Confirmed - GO asset offers are unchanged by the implementation of RTP.	There is no need to change the treatment of GO offers to implement RTP. The current dynamism of GO offers aligns with the design desire of reducing uplift costs.
24	Offers - IG and Type-B cogen remain as existing	IG and Type-B cogen are treated uniquely in the RTD schedule. Is this changed by the introduction of RTP?	Scope, ROM, and Code	Not considered.	Confirmed - out of scope	There is no justification to consider changes to the treatment of IG and Type-B co-generation in dispatch to introduce RTP. NB by default their treatment in settlement pricing will change.
25	Embedded/unoffered Generation	Does the introduction of RTP necessitate or benefit from changes to the current treatment of embedded/unoffered generation?	Scope, ROM, and Code	Not considered.	Confirmed - out of scope	There is no justification to consider changes to the treatment of embedded/unoffered generation to introduce RTP.
26	Gate Closure 1 hour	Gate closure is intended to be changed prior to RTP. What if any effect does this have on RTP?	Scope, ROM, and Code	Not considered.	Confirmed - out of scope	There is no justification to consider changes to Gate Closure to introduce RTP. RTP will be implemented with the Gate Closure period which applies at the time.
27	SFT	Potential for changes to be made to the frequency with which SFT is run and the schedule from which the SFT results are passed to the RTD schedule.	Scope and ROM	Not considered.	Decision – run SFT off the PRS schedules for input to RTD. Align the CAS schedule to be a PRS type schedule.	Authority analysis has shown the PRS schedule aligns more closely with final pricing. Further the inclusion of more bid information to the RTD schedule is further justification for this change.
28	RMT	Potential for changes to be made to the frequency with which RMT is run and the schedule from which the RMT results are passed to the RTD schedule.	Scope and ROM	Not considered.	Decision – run RMT off the PRS schedules for input to RTD. Align the CAS schedule to be a PRS type schedule.	Authority analysis has shown the PRS schedule aligns more closely with final pricing. Further the inclusion of more bid information to the RTD schedule is further justification for this change.

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29	Block dispatch	Potential for changes to be block/station dispatch to implement RTP.	Scope, ROM, and Code	Not considered.	Confirmed - out of scope	There is no justification to consider changes to block dispatch to introduce RTP.
30	Current 5-minute ex-post schedule	The current 5-minute ex-post schedule would serve no purpose if actual prices are being published in the same time-frame.	Retention or cessation of current 5-minute ex-post (RTP) schedule	ROM, Scope, and Code to reflect discontinuation of the Current 5-minute ex-post schedule.	Decision - the current 5-minute ex-post schedule would be ceased.	The 5-minute ex-post schedule was designed as a prototype RTP schedule and then morphed to be viewed as an indicator of ex-post final pricing. If RTP is implemented; there will be an actual RTP schedule and ex-post final prices will cease to exist.
A1	SPD solutions will use scarcity-based default bids and the Authority will decide the scarcity bid prices for default bidding.		Management of HSWPS / infeasibilities / Scarcity will need to be supported by the SPD RTD solution. This will replace the current manually effected administrative processes which currently exist.	If not implemented manual processes would be required to be replicated by NCC. This would be unworkable in a real-time environment. If nothing is done, then settlement prices would be impacted by the use of CVPs (as needed) in the RTP prices.	Assumed will result in economic load shedding	
A2	The Authority will determine the CE Instantaneous Reserve (IR) deficit "CVP" prior to RTP detailed solution design.		Is Industry consultation required? Reserve CVPs will be determined by the Authority. IR operational decisions remain with Transpower.	To maintain the current market outcomes during CE IR shortages post-RTP the current IR CE CVP values must be changed.	The Authority will determine IR CE CVP.	
A3	Consider the impact of RTP implementation on constrained on and off appropriateness reflect any changes required in the code.		Is Industry consultation required? Requirement to balance actual generation output/ancillary services with cleared quantities and the averaging of prices may create constrained costs.	No new data sets required from Transpower for settlement.	Confirm	
A4	Does NZX sub contract to TP or contract directly to the Authority for the WITs changes	NZX fulfils multiple service provider roles via contracts held with the Authority. These roles are impacted by the RTP project.	ROM does not include NZX costs	The Authority will manage the relationship with NZX.		

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A5	NZX will be able to update all their tools, WITS etc., to incorporate RTD requirements within the time frame required to implement the system operator RTP solution	There will be significant alterations to WITS to receive and display the altered data publication requirements associated with RTP. Further NZX may be the party tasked with the price averaging responsibility.	Updates to NZX tools will need to be incorporated as RTP implementation requirements so as to provide requisite interfaces to the system operator RTD solution.	If not implemented within the required timeframes RTD project benefits will not be realised. The proposed RTP solution will provide multiple prices per trading period. A mechanism for price averaging and providing information to interested parties (Transpower, Clearing Manager) will need to be confirmed and implemented.		
A6	EDF Phase 3 has been implemented to facilitate the issuing of different supplementary dispatch instructions	EDF Phase 3 will facilitate the dissemination of dispatch instructions more easily than the current 'GENCO system'.	Participant systems are modified to be able to receive different dispatch products and supplementary information	Automated dispatch of other products, i.e. load shedding, will be required to support the use of scarcity based bids for scarcity and High Spring Washer situation management. The work required to implement is large and significant for both the system operator and market participants.		
A7	The RTP solution will not require implementation of any changes to the RMT solver.	RMT runs following specific schedules to produce IR inputs for future schedules. Those IR inputs assist with optimal IR scheduling and provision of security.	Functional changes to RMT other than reviewing requirements for using RMT results in particular calculating reserves price requirement within RTP are not envisaged necessary.	A need for more frequent RMT solutions when multiple price calculations will be provided per trading period could be considered. Potential for RMT to be swapped to running on the PRS schedules. NB no functional changes to RMT calculation are required.		
A8	Gate Closure project changes are implemented prior to RTP detailed solution design	The gate closure reduction project will reduce gate closure from 2 hours to 1 hour.	Any gate closure project changes to RMT will be incorporated in the baseline RMT solution used by the RTP project.	None.		
A9	National Markets for Instantaneous Reserve (NMIR) project changes are implemented prior to RTP detailed solution design	Tool and process changes to implement NMIR are in-train currently (Oct/Nov 2016)	Any NMIR project changes to RMT will be incorporated in the baseline RMT solution used by RTP project.	None. NMIR went live November 2016.		

ID#	Design Parameter	Description	Effect of Item	Impact on Project	Decision or Confirmation	Rationale
A10	Costs associated with participants implementing changes for dispatching load will be funded separately to the system operator RTP project costs.	Participants may incur costs to update their systems to reflect changes associated with RTP. This may include changes to reflect altered data to/from WITS and mechanisms for receipt/acknowledgement of load dispatch instructions.	Any associated costs and changes to systems will need to be addressed separately by the Authority.	Extension of the dispatchable demand capability to participants with 5-minute response capability. Inclusion/awareness of at the UAT/participant phases.		
A11	Business process will be changed to manage implications of RTP on NCC.	RTP will wholly link dispatch to formation of settlement price. Consequently, all NCC actions which impact dispatch may also affect settlement price.	Consideration will need to be given to what NCC actions, if any, need to be Codified and or amended such that participants and Transpower are happy with the outcomes of those processes. Significant process change is envisaged as co-ordinator actions will impact inputs used for RTD pricing. **NB in doing so it should be the case operational decisions are accepted as part of the process not pricing outcomes forcing operational outcomes.**	With price publication occurring more frequently the project will need to consider NCC use of discretion and the actions to be taken when situations impacting price exist. Participants responding to and querying prices may result in an increase in co-ordinator manual workload. This will need to be reviewed for any associated business process change or altered resourcing requirements.		
A13	Settlement will continue to be for 30-minute trading periods.	Settlement of the market requires alignment of settlement prices and settlement volumes to an agreed trading period.	The market will retain settlement on 30-minute trading periods.	None - retention of the 30-minute trading periods for pricing and settlement means this is unchanged.		
A14	Settlement will be based upon the real time pricing option.	Settlement of the market requires a settlement price to be produced.	The market will use the settlement price produced by the RTP solution to settle the market.	Successful implementation of the RTP project achieves this.		

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A15	Uplift will still be required to balance actual generation output with cleared quantities, and ancillary services constrained costs.	While uplift will be reduced under a RTP regime it will not be completely eliminated. By definition a price averaging methodology will result in settlement prices lower than some of the prices from which it was derived. As a result, uplift will still exist. Existing sources of uplift, i.e. frequency keeping and IR optimisation, are unchanged by the implementation of RTP.	Need to retain both tools and Code based functionality to calculate and settle uplifts. Messaging to participants will need to include this fact.	Retain current uplift functionality.		
A16	TAS 60 will not assess any impact to the Reconciliation Manager and Clearing Manager roles and work because a single half hour price is retained.	The RTP project exists to alter the way the settlement prices are calculated. Settlement prices are used by the clearing manager when settling the market. The clearing manager uses settlement prices and half-hourly volumes from the reconciliation manager to clear the market.	Any change from 30-minute trading periods for both settlement pricing/volumes would have a significant impact on the Reconciliation Manager and Clearing Manager roles.	None - retention of the 30-minute trading periods for pricing and settlement means this is unchanged.		
A17	Expected impacts to the Pricing Manager role and WITS system costs are not considered under this TAS60. Changes are commented on as appropriate in the TAS report.	This project will have significant impacts on the pricing manager and the WITS manager roles.	There are multiple interfaces and relationships between Transpower and NZX for WITS and pricing manager functions. Transpower's remit (and abilities) are limited to 'our-side-of-the-fence' only.	To be managed by the Authority.		

Appendix 2: AUTHORITY DESCRIPTION OF RTP BIDS

Eligible participant	Location	Dispatchable?	Met conditions to receive constrained payments?	Outcome	Bid type
Purchasers and load aggregators	Non-conforming node (must submit bids)	Yes	Yes	This is existing DD compliant option at non-conforming node • Bids can set price • Equivalent to existing DD and dispatched generators • Must comply with dispatch instructions but for bona-fide physical reasons	ENDL "Y" Dispatchable DD bid
			No	This is new 'dispatch lite' option • Bids can set price • Compliance monitored and dispatch - could be revoked if abused/misused • Must comply with dispatch instructions during a grid emergency	**ENXX** **NEW**
		No (mandatory bid is statement of intent)	No	This is existing non-DD participant at non-conforming node • Bid prices and quantities discarded – scarcity prices assigned to persistence forecast. • Must comply with instructions in grid emergency	ENNC A 'normal' NCL bid

				• Can respond to forecast and real time prices	
	Conforming node (may submit bids)	Yes	Yes	This is existing DD compliant option at conforming node • Bids can set price • Equivalent to existing DD and dispatched generators • Must comply with dispatch instructions but for bona-fide physical reasons	ENDL "Y" Dispatchable DD bid
			No	This is new 'dispatch lite' option • Bids can set price • Compliance monitored and dispatch - could be revoked if abused/misused • Must comply with dispatch instructions during a grid emergency	**ENZZ** **NEW**
		No (optional bid is statement of intent)	No	This is existing 'default' option for bids at conforming node • Any bid prices and quantities discarded • Can only respond to forecast and real time prices	ENDF Difference bids