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Compiled by	Approved by	Authorized by
Rosalette Botha	Ernest Mpshe	Comfort Masike
Corporate Specialist System Operator	Middle Manager National Control System Support	Senior Manager Technical Operations
Date: 05/11/2021	Date: 09/11/2021	Date: 01 /12/2021

Supported by SCOT/SC

Nelson Luthuli

Acting PTM&C TC Chairperson

Date: 12 November 2021

PCM Reference: **n/a**

SCOT Study Committee Number/Name: **Telecontrol & SCADA SC**

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1. Introduction

The *Employer* is the South African power utility, with an installed capacity in excess of 45 000 MW of Gas, Hydro, Pumped storage and other Renewable Energy Sources, Nuclear, DC-AC conversion and predominantly Coal Fired Steam generation. Peak consumption is in excess of 34 000 MW. The *Employer*, as a member of the Southern African Power Pool, trades energy with other Southern African power utilities and is looking forward to expanding its transmission network further in order to increase sales into Africa. In an effort to reduce the impact on the environment, the *Employer* is gradually transitioning to a cleaner energy mix including more renewable energy mainly provided by Independent Power Producers. The *Employer* shall evolve as per the Roadmap for Eskom in a reformed Electricity Supply Industry (ISBN: 978-0-621-47981-2) published in 2019.

The *Employer* has a single System Operator (operating under the licensed National Transmission Company) whose mandate is to control the operation and be responsible for the short-term reliability of the Interconnected Power System as defined in the South African Grid Code. This is achieved using the Transmission Power System Control and Monitoring tools.

Transmission Power System Control and Monitoring includes the Energy Management System, Wide Area Monitoring System and the Generation Dispatch System.

This document details the requirements for a request for proposal from the market to ensure the sustainability of such a system in terms of:

- Engineering Requirements (Design, Process, Cyber Security, Testing and Operational)
- Functional Requirements (Graphical User Interface, Operator Training Simulator, Energy Management System, Generation Dispatch System and Control Centre Wide Area Monitoring System)

2. Supporting clauses

2.1 Scope

The objectives of this RFP is to:

- Source a complete or partial TPSCM solution for an Energy Management System (EMS), Wide Area Monitoring System (WAMS), Generation Dispatch System (GDS), and an Operator Training Simulator (OTS).
- Obtain costs provided in ZAR excluding VAT for the TPSCM solution. If costs are subject to exchange rate changes, the foreign portion and exchange rates used must be provided.

It is imperative to note that the document does not necessarily imply a requirement for a single system solution. Details, technical and financial, shall be provided where third (3rd) party solutions are integrated in the TPSCM.

The RFP scope is to enable the provision of a sustainable solution for an Energy Management System, Wide Area Monitoring System, Generation Dispatch System and Operator Training Simulator (OTS) for all control room functions, as well as a development environment for real-time and offline operations at the Primary Control Centre (PCC) and Secondary Control Centre (SCC) site. The SCC site could also fulfil the role of a Disaster Recovery Site. The solution shall cater for distributed functions in the national and regional control centres as well as control centres for other specialised System Operator service providers. The solution shall interface to the Transmission Division's telecommunications equipment and Enterprise Information Systems. An integrated rear projection system is required. A migration path for *Employer* data and displays shall allow for transparent parallel operation of the systems during commissioning and system integration.

2.1.1 Purpose

The purpose of this document is to clearly define the requirements for a Transmission Power System Control and Monitoring system.

2.1.2 Applicability

This document shall apply to the Transmission System Operator.

2.2 Normative/informative references

Parties using this document shall apply the most recent edition of the documents listed in the following paragraphs. All national and international documents referenced shall be obtained directly from the source.

2.2.1 Normative

[1] ISO 9001, Quality Management Systems.

[2] 240-55410927 Cyber Security Standard for Operational Technology

[3] 32-373 Information Security - IT/OT Remote Access Standard

[4] SD-OT/0010001: Security Division Position Paper – Cloud Computing

[5] 240-61478980 Eskom Slave device IEC 60870-5-101 Implementation Standard

[6] 240-61478967 Eskom Master device IEC 60870-5-101 Implementation Standard

[7] 240-72942279 EMS and DMS Master Station Computer Disaster Recovery Standard

[8] 240-91479924 Cyber Security Configuration Guidelines of Networking Equipment for Operational Technology

[9] The South African Grid Code -The Information Exchange Code

[10] 240-82331576: Inter Control Centre Communications Protocol Standard

[11] 240-160474571 Measurement and recording of Eskom frequency

[12] Data Centre Tier Levels https://uptimeinstitute.com/tiers

[13] IEEE C37.118.2 IEEE Standard for Synchrophasor Data Transfer for Power Systems

[14] ICCP /IEC 60870-6-503 standard

[15] Grid Connection Code for Battery Energy Storage Facilities (BESF) connected to the electricity Transmission System (TS) or the Distribution System (DS) in South Africa

2.2.2 Informative

[16] Electricity Supply Industry (ISBN: 978-0-621-47981-2)

[17] IEEE 802.1X IEEE Standard for Port-Based Network Access Control (PNAC)

[18] IEC 60870-5-104 Transmission Protocols - Network access for IEC 60870-5-101 using standard transport profiles

[19] The South African Grid Code

2.3 Definitions

2.3.1 General

Definition	Description
Git	Git is a distributed version control system for tracking changes in source code.
Kelman System	The *Employer's* Dissolved Gas Analyser system from General Electric Kelman.

Definition	Description
Remote Terminal Equipment	The remote terminal equipment refers to any remote device, such as a telecontrol Remote Terminal Unit (RTU), Distributed Control System (DCS) or gateway.

2.3.2 Disclosure classification

Controlled disclosure: controlled disclosure to external parties (either enforced by law, or discretionary).

2.4 Abbreviations

Abbreviation	Description
AC	Alternating Current
ACE	Area Control Error
AFAS	Automatic Fault Analysis System
AGC	Automatic Generation Control
API	Application Programming Interface
ARC	Auto-Re-Close
BCD	Binary-Coded Decimal
BERT	Bit Error Rate Test
BME	Bandwidth Management Equipment
CIM	Common Information Model
CIP	Critical Infrastructure Protection
CPS	Control Performance Standard
CPU	Central Processing Unit
CRC	Cyclic Redundancy Check
CSP	Concentrated Solar Power
DC	Direct Current
DCS	Disturbance Control Standard
DDS	Detailed Design Specification
DEC	Data and Energy Centre
DGA	Dissolved Gas Analyser
DMS	Distribution Management System
DMZ	Demilitarized Zone
DR	Disaster Recovery
DSA	Dynamic Security Assessment
DSO	Distribution System Operator
EDS	Electronic Dispatch System

Abbreviation	Description
EMS	Energy Management System
EOS	Equipment Outage Scheduling
FACTS	Flexible AC Transmission System
FAT	Factory Acceptance Test
GDS	Generation Dispatch System
GIS	Generation Information System
GPS	Global Positioning System
GUI	Graphical User Interface
HIS	Historical Information System
HVDC	High Voltage, Direct Current
ICCP	Inter Control Centre Protocol
IEC	International Electrotechnical Commission
IED	Intelligent Electronic Device
IEEE	Institute of Electrical and Electronics Engineers
IMM	Integrated Management Module
IPP	Independent Power Producer
IPS	Interconnected Power System
ISBN	International Standard Book Number
ISO	International Organization for Standardization
IT	Information Technology
ITS	Interchange Transaction Scheduling
kV	kilo Volt
LAN	Local Area Network
LED	Light Emitting Diode
LLS	Lightning Locating System
MAPE	Mean Absolute Percentage Error
MCR	Maximum Continuous Rating
MFA	Multi-Factor Authentication
MTLF	Medium Term Load Forecast
MVA	MegaVolt Amperes
MVAr	MegaVars
MW	Mega Watt
NERC	North American Electric Reliability Corporation
NMC	Network Management Centre
ODBC	Open Database Connectivity

Abbreviation	Description
OEM	Original Equipment Manufacturer
OSI	Open Systems Interconnection
OT	Operational Technology
OTS	Operator Training Simulator
PCC	Primary Control Centre
PDC	Phasor Data Concentrator
PFA	Power Flow Analysis
PLC	Programmable Logic Controller
PMU	Phasor Measurement Unit
PV	Photovoltaic
RAID	Redundant Array of Inexpensive Disks
RCC	Regional Control Centres
RFP	Request For Proposal
RTE	Remote Terminal Equipment
RTU	Remote Terminal Unit
SAGC	South African Grid Code
SAPP	Southern African Power Pool
SAT	Site Acceptance Test
SCA	Short Circuit Analysis
SCADA	Supervisory Control and Data Acquisition
SCC	Secondary Control Centre
SCO	Synchronised Condenser Operation
SCS	Substation Control Systems
SIEM	Security Information and Event Management
SMS	Short Message Service
SNTP	Simple Network Time Protocol
SOC	System Operating Control
SOE	Sequence Of Event
SPDC	Substation class Phasor Data Concentrators
SSSA	Small Signal Stability Assessment
STATCOMS	Static Synchronous Compensators
STLF	Short Term Load Forecast
SVC	Static VAr Compensator
TCP	Transmission Control Protocol
TEMSE	Transmission Energy Management System Evolution

Abbreviation	Description
TPSCM system	Transmission Power System Control and Monitoring
TSA	Threat Susceptibility Assessment
TSO	Transmission System Operator
TWS	Travelling Wave System
UDP	User Datagram Protocol
UI	User Interface
UPS	Uninterruptible Power Supply
USB	Universal Serial Bus
VAT	Value Added Tax
VLAN	Virtual Local Area Network
VPN	Virtual Private Network
WAMS	Wide Area Monitoring System
WAN	Wide Area Network
WPF	Windows Presentation Foundation
XML	Extensible Markup Language
ZAR	South African rand

2.5 Roles and Responsibilities

Tenderers shall refer to the *240-170000482 Overview of requirements for the Transmission Power System Control and Monitoring System* to ensure the submission is considered responsive.

2.6 Process for monitoring

The Request for Proposal (RFP) conforms to the Technology Development Methodology and will follow the *Employer's* procurement processes.

2.7 Related/supporting documents

None

2.8 Schedule Guidelines

This Request for Proposal shall ask for detail of the Suppliers standard offering, identification of unique *Employer* requirements, guidance on the scope of the new solution and how to migrate to the new solution.

Both the Requirement Schedule and the Option Schedule states the *Employer's* firm requirements. The *Employer* reserves the right to select requirements from the Option Schedule within the TPSCM solution.

Electronic copies of documents / schedules must be provided.

1) Requirement Schedule:

Requirement	Standardisation
1) The Graphical User Interface shall be intuitive.	Standard

a) Requirement

Provides a description / statement of the *Employer's* requirement and/or expectation.

b) Standardisation

The *Supplier* can indicate with:

1) Standard – indicates that this is part of the standard implementation of the solutions
2) Partial – indicates that some engineering / modification to the standard product is required to meet the requirement.
3) New – this is a new requirement.

Supporting documentation and references are required for all "Standard" and "Partial" compliant requirements.

2) Option Schedule: <Title>

Requirement	Standardisation
1) The *Supplier* shall migrate all *Employer* data and displays for the TPSCM.	Standard

a) <Title>

The category is to be used for option in the Pricing Schedule.

b) Requirement

Provides a description / statement of the *Employer's* requirement and/or expectation.

c) Standardisation

The *Supplier* can indicate with:

1) Standard – indicates that this is part of the standard implementation of the solutions
2) Partial – indicates that some engineering / modification to the standard product is required to meet the requirement.
3) New – this is a new requirement.

Supporting documentation and references are required for all "Standard" and "Partial" compliant requirements.

3. Transmission Power System Control and Monitoring (TPSCM system)

3.1 Background

The operating, control and monitoring of the Interconnect Power System (IPS) requires a single integrated seamless solution, the Transmission Power System Control and Monitoring (TPSCM) system, in the control centres. This document details the *Employer*'s expectation with regard to all the components and sub-systems contributing to the solution as well as the extent to which the integration of the components shall provide a transparent / seamless solution for the end-user.

3.1.1 Philosophy

The upgrade and/or migration of the Energy Management System (EMS), Wide Area Management System (WAMS) and Generation Dispatch System (GDS) shall comprise standard hardware and software with special developments being kept to a minimum. A single Graphical User Interface and Operator Training Simulator shall be provided for the EMS, WAMS and GDS.

Requirement Schedule:

i.	Special developments shall be clearly identified and documented as to their nature and depth in a delta design document.
ii.	The *Employer* shall augment the TPSCM solution with in-house and third-party applications and tools to assist with the maintenance and support of the TPSCM.
iii.	The TPSCM architecture shall indicate how software upgrades can be effected in a controlled manner by the addition or alteration of software modules to the base system without interruption to the operating and control of the Interconnected Power System from the control centres.
iv.	The EMS, WAMS and GDS shall be based on a proven EMS, WAMS and GDS platform.
v.	Any enhancements to the EMS, WAMS and GDS shall be seamlessly integrated in the Graphical User Interface (GUI) and OTS.
vi.	The TPSCM shall be on the supported release for the full duration of the life cycle of the solution.

Option Schedule: Maintenance Agreement – Standard

vii.	The TPSCM solution shall be in production for at least fifteen (15) years.
viii.	The EMS shall maintain the upgradeability and modularity to cater for the developing requirements of the electricity industry.
ix.	All delta designs shall be supported by a migration path to be included in the future product releases.
x.	The support from the original supplier shall be available for an annual incremental migration of the system.
xi.	The supplier shall maintain infrastructure and configurations representative of the TPSCM solution to reproduce and investigate reported faults.

Option Schedule: Maintenance Agreement – WAMS

xii.	The WAMS shall maintain the upgradeability and modularity to cater for the developing requirements of the electricity industry

Option Schedule: Maintenance Agreement – GDS (Replacement)

xiii.	The GDS replacement solution from the supplier shall maintain the upgradeability and modularity to cater for the developing requirements of the electricity industry.

xiv.	The integration of the GDS solution shall be maintained with the migration of the TPSCM required for the upgradeability and modularity to cater for the developing requirements of the electricity industry.

3.2 Engineering Requirements

3.2.1 Design Requirements

3.2.1.1 Business Structure

3.2.1.1.1 Organisational Background

The *Employer* is historically a vertically integrated utility that generates, transmits and distributes electricity. It is a registered company, with ownership vesting in the South African government. For more information, refer to the *Employer*'s web site: www.eskom.co.za

3.2.1.1.2 System Operator

The System Operator is responsible for the safe, efficient transmission of electrical power in the Republic of South Africa and performs the following functions:

- Instruct all operating on all Interconnected Power System (IPS) equipment.
- Grant approval for transmission system equipment outages for IPS equipment.
- Control voltage by transformer tap changing and/or reactive device switching on the power network.
- Dispatch bulk electricity to satisfy contracts.

Southern African Power Pool responsibilities of the System Operator are:

- Controlling the frequency for the South African grid as well as for other Southern African countries.
- Scheduling trade agreements.
- The exchange of information from the Interconnected Power System with the Southern African Power Pool

The main power system operating objective is to ensure that the power system achieves a high degree of reliability when operating within established limits by knowledgeable personnel.

The TPSCM system shall be used for the operating and control of the Transmission Interconnected Power System.

System Operator exchanges information with other participants of the Electricity Supply Industry in the Republic of South Africa including Network Service Providers and Independent Power Producers (IPP). Hence, sub-transmission network information is available for complete network modelling and observability.

Information from the Southern African power system is exchanged with the Southern African Power Pool and all the members.

3.2.1.2 Architecture

3.2.1.2.1 Criteria

The fundamental design criteria for the design and implementation of the TPSCM system are high availability, high reliability and maintenance simplicity.

Requirement Schedule:

i.	The desired high availability shall be achieved by means of hardware and software redundancy with failover and/or clustering mechanisms where this is practically achievable even during power system disturbance conditions to the equipment rooms.
ii.	High reliability shall be achieved through the installation of a field-proven system based on industrial best practices, principles and guidelines.
iii.	Maintainability shall be achieved through system monitoring and configuration management.
iv.	Hardware components which are identified as critical shall be duplicated in each computer room to allow for software and hardware upgrades without losing the overall redundancy criteria during the period of upgrade or failure.
v.	All high availability architecture shall be documented as to technology used on hardware, operating system, database management system and application layer. The complete configuration shall be submitted as part of the Detail Design Specification.
vi.	The functionality shall include a complete system build and deployment from a single source.
vii.	It shall be possible to have a complete system recovery within an hour.
viii.	Performance criteria shall be measured across the TPSCM solution and separate per site for the PCC and the SCC.
ix.	Where available, technologies which will reduce the total cost of ownership shall be used.

3.2.1.2.2 Redundancy

The Primary Control Centre (PCC) is housed in two (2) buildings located adjacent to each other with direct access to the Data and Energy Centre (DEC). The DEC has four (4) redundant equipment rooms which are available to the dual redundant TPSCM system.

The Secondary Control Centre (SCC) is located about 150km from the Primary Control Centre. A data centre configured with either three (3) redundant equipment rooms or a single non-redundant equipment room is available in the same building as the System Operating Control (SOC) room. The SOC has a dual role/function of system operating and control centre as well as a manned standby control centre.

Requirement Schedule:

i.	The full redundancy of the production system at the PCC / DEC shall be extended over two (2) separate equipment rooms without any interdependencies.
ii.	The third (3rd) clustering / voting node, if required, shall be located outside the redundant configuration.
iii.	The development / pre-production / testing environments shall be isolated from the operational / production system.
iv.	The data and display engineering shall be included in the development environment, but it is regarded as part of the production system.
v.	The data and display engineering shall have a redundant architecture across the sites.
vi.	Data and display consistency in the development environment across the sites shall be automatic and transparent.
vii.	The production system at the SCC shall be a mirror of the system at the PCC and the transfer of the operating and control between the two (2) sites shall be seamless.

viii.	The data, display engineering and code management shall be available at the PCC and SCC with at least one site active / online. Offline data and configurations shall be synchronised on demand after any change / database update.
ix.	Redundancy shall be available for all data transfer done through a Data Gateway in the Demilitarized Zone (DMZ).
x.	Non-production servers (except for pre-production) in the development and testing environment shall be virtualised where feasible and run on common physical servers using virtualisation software.
xi.	Client user interface on workstations shall be virtualised on Linux using Kernel-based Virtual Machine.
xii.	The provided solution shall not reduce the expected reliability and availability of the TPSCM system as defined for a Tier IV Server Rooms and Data Centres as per UptimeInstitute definition (Data Centre Tier Levels https://uptimeinstitute.com/tiers). The data centres will have redundant connection to the single substation on the IPS.
xiii.	An Operator Training Simulator shall be available at both the PCC and the SCC physically and logically removed from the production TPSCM system.
xiv.	A replicated TPSCM system shall be available in the Demilitarized Zone (DMZ) for real-time visibility and offline studies without affecting the real-time control environment.
xv.	The TPSCM system shall be able to withstand regular loss of power, and to automatically restore to operational state, either as master or standby / reserve function without human intervention and/or data corruption.
xvi.	The TPCM shall utilise the communication to the RTEs from the PCC and SCC as redundant paths regardless of which site is the active master and the protocols used to the RTEs.
xvii.	Redundancy for the rear projection system shall be maintained from the source up to the common physical display unit.
xviii.	The OTS shall be available through the secure DMZ to the users on the *Employer's* corporate network for dedicated training scenarios.

3.2.1.2.3 Business Continuity

The TPSCM system shall have a single Disaster Recovery and Business Continuity Manual, which will ensure the solution complies with the requirements of the Cyber Security policy for Operational Technology. Redundancy of the TPSCM system at the PCC and SCC sites shall enable database and display deployment to be done on the non-active site first. The non-active site can be used as a Quality Assurance system. PCC and SCC control rooms shall have access to the DMS systems to have visibility of the Distribution network.

Requirement Schedule:

i.	The pre-production system shall be configurable for use as quality control and the process and documentation shall be verified during the SAT.
ii.	Backups for business continuity shall be done on the non-active site such that no functionality is lost during the backup and/or restore. Thus, when a single node is required for backup, a non-redundant TPSCM system shall be available at the non-active site as a disaster recovery system. This shall ensure there are always three (3) nodes operational, i.e., dual redundancy at the active site and a single node operational at the non-active site for disaster recovery.
iii.	The Wide Area Network (WAN) between the PCC and SCC sites shall ensure that the switch, between the sites, shall be transparent to the control room with no data loss.
iv.	It shall be possible to schedule switch overs between the sites to ensure the active site remains dual redundant, even during the deployment of new data and displays.

v.	Server and workstation reconfiguration shall not put the power system at risk of unauthorised operating and control. Role-based authentication per user shall be used to ensure the secure mapping and blocking of functions to a workstation / server during the reconfiguration to prevent a potential operating error. An alert shall be configurable to prompt users to login during shift change over.
vi.	Any data required for any operational function shall have a backup version for rapid recovery that can be automatically brought into use without loss of data or functionality as part of a restart or transfer procedure.
vii.	Periodic system maintenance shall not reduce the efficiency of the system failure recovery.
viii.	There shall be a functionality to alarm any data mismatch between the SCC and PCC.
ix.	It shall be possible to reconfigure all functionality, excluding the historians, on the pre-production system as a replicated dual-redundant production system to test and verify the deployment of new system configurations. The testing shall include the failover and recovery of the nodes. Typically, the functional nodes, such as data acquisition servers and/or application servers, can be included in the reconfiguration.
x.	The *Employer* shall use third (3rd) parties and third (3rd) party software / tools to evaluate the deployment of hardware, operating system and database management system technologies / mechanism for high availability solution in the management of data and display integrity during system failover and / or switchovers.
xi.	An application layer system failover and/or system switch-over shall not result in any data loss. These include all telemetry and operator entered data for operating and control of the Interconnected Power System, advanced network and generation functions.
xii.	The observability of the Distribution network shall be available for any operating and control of the Interconnected Power System, advanced network and generation functions.

3.2.1.2.4 Network Segmentation

Network segmentation shall be used in support of the Employer's Cyber Security policy for Operational Technology. The segmentation shall provide five (5) levels of security zones which reflect common or shared security attributes. Multiple security domains can reside on the same level, see the levels below:

- **Level 0 – Red Zone: External Domains**

Infrastructures that are not under direct or delegated control must be placed in the Red Zone. All external systems in the Red Zone should be considered insecure.

- **Level 1 – Orange Zone: Corporate DMZ**

Infrastructures that are exposed to a larger, untrusted network are placed in the Orange Zone. The network does not connect directly to the control system services.

- **Level 2 – Yellow Zone: Internal Domains**

Infrastructures that are under direct or delegated control and that are not directly related to managing, monitoring, or controlling elements of the electricity grid are placed in the Yellow Zone.

- **Level 3 – Green Zone: Control System DMZ**

Infrastructures that contain and expose the control system services to a larger, untrusted network (usually a partner's network) are placed in the Green Zone. The Green Zone is also called the "Control System DMZ". These secured systems include ICCP / IEC 60870-6-503 servers, historian servers, control system web servers.

- **Level 4 – Blue Zone: Control System Domains**

Infrastructures that are under direct or delegated control and that are directly related to managing, monitoring, or controlling elements of the electricity grid must be placed in the Blue Zone.

Requirement Schedule:

i.	The TPSCM system operational network shall be segmented to control the data flow and/or access between users and/or processes in the different security zones.
ii.	High risk end-user and/or data acquisition servers configured in client-server architecture or dedicated data acquisition server shall be isolated behind the supporting and/or application server in a VLAN.
iii.	The system shall have separate VLAN segments for the data acquisition servers isolated behind the application servers.
iv.	The system shall be configured with separate VLAN segments for the workstations in the PCC and SCC isolated behind the application servers.
v.	A physically separate Integrated Management Module (IMM) network for out-of-band maintenance and management of all servers and networking equipment shall be implemented with dedicated engineering workstations in 10 (ten) locations split across the PCC and SCC.
vi.	Two (2) Global Positioning System (GPS) units shall be provided, for PCC and SCC, for time synchronisation on the IMM network.
vii.	Five (5) security levels, as defined above, shall be configured and all servers shall be mapped to one of the security zones.
viii.	Port numbers shall be user configurable where feasible. Standard and/or fixed port numbers shall be documented and requires acceptance.
ix.	Network and host firewalls shall be configured to deny all traffic by default, except explicitly designated traffic. The open ports shall be limited as part of the installation and hardening of the operating system and prior to the installation and configuration of the TPSCM software.

3.2.1.2.5 Regional and Remote Control Centres

Regional Control Centres (RCC) are located at eight (8) sites and are equipped with remote workstations provided with full TPSCM system functionality. Communications to these remote sites are provided via redundant or non-redundant WAN connections from the PCC only or both the PCC and SCC. The Regional Control Centres perform agent SOC functions for the region on behalf of the System Operator.

Remote workstations are also provided in three additional sites namely, the two (2) Fault Management Centres and the Security control room. These control rooms allow for the 1) monitoring and /or resetting of RTU scanning and 2) the monitoring of security alarms, respectively.

Requirement Schedule:

i.	Eleven (11) remote workstations shall have secure connection with full TPSCM functionality controlled by the role based responsibility and access control.
ii.	Remote workstations shall have at minimum a single 30-inch monitor.
iii.	The Graphical User Interface image on the remote workstations shall be virtualised on a Linux host. The Linux host shall be capable of running two (2) Graphical User Interfaces images simultaneously.
iv.	Fibre network connectivity shall be provided to and at the regional and remote-control centres at the PCC.

3.2.1.2.6 Maintenance and Engineering Workstations

Engineering and maintenance workstations are concentrated mostly in the offices at the Primary Control Centre. Air conditioning is provided in all areas, and power supply from UPS is available for all computer equipment in the building. The transfer of some of the engineering and maintenance workstations, to the Secondary Control Centre, may be considered as part of the disaster recovery process.

Requirement Schedule:

i.	Corporate / IT workstations shall be used as secure engineering workstations for offline network studies in the Demilitarized Zone (DMZ) on real-time data without impacting the production TPSCM system.
ii.	Maintenance workstations shall be used for the maintenance and support of the TPSCM system. Additional logical access control shall limit access to the TPSCM network for maintenance workstations.
iii.	The TPSCM shall be configured to ensure that no maintenance workstations can be used for operating and control of the Interconnected Power System.
iv.	Workstations, external to the *Employer's* intranet, shall conform to all the *Employer's* remote access policies and standards.
v.	The Graphical User Interface image on the workstations on the TPSCM network shall be virtualised on a Linux host. The Linux host shall be capable of running two (2) Graphical User Interfaces images simultaneously.
vi.	Nine (9) maintenance workstations shall be used for data and display engineering and requires at minimum two (2) 30-inch (30") monitors.
vii.	Additional rack mounted maintenance workstations and monitors shall be provided in each of the server rooms.

3.2.1.2.7 Data Acquisition

The EMS/WAMS shall communicate via independent redundant communication circuits from the PCC and SCC, respectively, with the:

- Transmission substations;
- external transmission or distribution substations;
- Generation power stations; and
- Independent Power Producers (IPP).

equipped with either:

- single/multiple RTE; or
- Phasor Measurement Unit / substation class Phasor Data Concentrator; or
- distributed Substation Control Systems (SCS); or
- substation automation systems

utilising one of the following communication protocols:

- IEC 60870-5-101; or
- IEC 60870-5-104; or
- ICCP / IEC 60870-6-503 secure and/or non-secure; or
- C37.118 (PMU).

Requirement Schedule:

i.	Certified commissioning and support, according to the *Employer*'s standards and performance requirements, shall be provided for serial communication protocols, IEC 60870-5-101.
ii.	A single independent RTE per power station shall be used for AGC, controlling up to 16 generators simultaneously with the current IEC 60870-5-101 protocol implementation of a 32-bit command string.
iii.	The TPSCM system shall be able to exchange data with any DMS and other service providers like aggregators using ICCP / IEC 60870-6-503.
iv.	Certified support shall be provided for IP protocols, IEC 60870-5-104 and ICCP / IEC 60870-6-503.
v.	It shall be possible to define the number of data sources for every SCADA data item. For any modelled data item, a minimum of four (4) data sources shall be identified with automatic failover between the sources.
vi.	The health of the substation equipment, for example: bay processor, plant card, substations automation equipment and IEDs shall be monitored by the TPSCM.
vii.	The communication circuits to either the PCC or the SCC shall be used during migration/upgrade of the TPSCM system, without requiring changes to the configuration of the RTE, for testing and parallel operations. The parallel operation of the TPSCM system shall not degrade the performance and availability of the production system, TEMSE, for the operating and control of the Interconnected Power System.
viii.	The 32-bit command string or equivalent required for AGC shall also be available in the IP based protocol implemented as part of the TPSCM solution, i.e., the functionality shall also be implemented in IEC 60870-5-104.

3.2.1.2.8 System Sizing

The current system sizing is:

- 300 000 Status Indications;
- 50 000 Analogues;
- 1 000 Substations / Power stations;
- 7 000 Busbars;
- 2 500 Transformers;
- 1 000 Generators; and
- 5000 Loads.

Requirement Schedule:

i.	No predefined system sizing shall be required. Databases used for static and reference data shall be sized to have an additional ten percent (10%) capacity per database table / record type prior to Phase 3 –Development, System Integration and FAT.
ii.	Additional capacity to the current system sizing shall be available for power system operational data of fifty percent (50%) per database table / record type prior to Phase 3 –Development, System Integration and FAT.
iii.	Provision shall be made for three hundred (300) serial communication ports plus a forty (40%) percent additional capacity per equipment room where a data acquisition system is located at the SCC and PCC.

iv.	The fifty percent (50%) threshold shall be maintained during the migration / upgrade of the TPSCM system as part of the Maintenance and Support.
v.	All performance requirements shall be met based on the sizing requirements as above.

3.2.1.3 Standards

The TPSCM system shall conform to international industry standards with respect to all hardware, software, operating systems and database implementations. An open architecture shall be provided, supporting the ongoing evolution of these standards, additional development of existing functionality provided by the TPSCM system and the integration of new functionality.

3.2.1.3.1 Hardware

The *Employer* shall involve the approved hardware supplier during the initial work statement to finalise the hardware configuration and discuss the following issues:

- Certification of hardware with proposed operating systems and third (3rd) party software;
- Certification of hardware for any high availability cluster support; and
- Local support policies.

Requirement Schedule:

i.	It shall be possible to upgrade the hardware performing the critical cyber security function to facilitate the deployment of the latest firmware and patches.
ii.	The proposed hardware for the TPSCM system shall be evaluated against the hardware standards from the *Employer*.
iii.	The TPSCM system shall be installed on native hardware. Virtualisation may only be considered for non-production systems. However, the pre-production systems shall not be virtualised.
iv.	The hardware, operating systems and third (3rd) party software shall be procured and installed directly by the *Employer* or its subcontractors with approval from the Original Equipment Manufacturer/s (OEM/s) of the TPSCM solution.
v.	The hardware installations shall be verified during the site acceptance test (SAT) through the re-installation of the OS and third (3rd) party software.
vi.	As part of the pre-installation of the TPSCM, a hardware validation and quality control / benchmark for performance shall be done.
vii.	A Cyber Threat Susceptibility Assessment (TSA) to evaluate the susceptibility of the TPSCM solution to a cyber-attack shall be performed on the hardened TPSCM solution.

Option Schedule: Hardware – Core

viii.	The core hardware shall support all design requirements of the TPSCM. All subsystems defined as part of the core shall be listed.

Option Schedule: Hardware – Rear Projection System

ix.	TPSCM hardware shall include one or more rear projection systems.

x.	The rear projection systems shall meet the requirements defined in 0.
xi.	TPSCM hardware shall include a DStv decoder.

Option Schedule: Hardware – Front Projection System

xii.	TPSCM hardware shall include one or more front projection systems.
xiii.	The front projection system shall meet the requirements defined in 3.2.1.4.8.

Option Schedule: Hardware – Cyber Security

xiv.	The TPSCM solution shall include special tools and analysers to manage the cyber security risk.
xv.	It shall be possible to ensure the quick recovery of all servers and workstations while preserving the evidence of a potential cyber-attack.

Option Schedule: Hardware – Workstations and Monitors

xvi.	Specification for all workstations shall include 32G RAM; dual network cards, suitable graphic controller card to support 4 monitors, one (1) processor, eight (8) cores and at least 1TB disk capacity.
xvii.	A total number of 140 workstations shall be installed.
xviii.	Thirty (30) four (4) headed operator workstations shall be installed.
xix.	A total number of three hundred and forty (340) thirty-inch (30”) monitors shall be installed.

Option Schedule: Hardware – Data Acquisition

xx.	The telecommunication interface shall be delivered with patch / break-out panels to be able to connect a third (3rd) party line analyser and test equipment without disconnecting any operational equipment.

Option Schedule: Hardware – Generation Dispatch System (Replacement)

xxi.	The architecture for the GDS shall be consistent with the TPSCM to meet the requirements defined in 3.3.5 excluding the provision of the 3.3.5.9.

Option Schedule: Hardware – Generation Dispatch System (Integration)

xxii.	The production GDS shall be migrated to new hardware retaining the architecture and data flow. However, provision shall be made for redundancy at the SCC.
xxiii.	Four (4) servers shall be provided at PCC and two (2) severs at SCC.

Option Schedule: Hardware – Electronic Dispatch System (Replacement)

xxiv.	The architecture for the EDS shall be consistent with the TPSCM to meet the requirements defined in the 3.3.5.9.

Option Schedule: Hardware – Electronic Dispatch System (Integration)

xxv.	The production Electronic Dispatch System shall be migrated to new Data Gateway hardware as defined by the TPSCM functions while retaining the architecture and data flow.

3.2.1.3.2 Licensing

Requirement Schedule

i.	The TPSCM system shall use open-source licenses where available.
ii.	All proprietary licenses shall be listed and the licensing model in respect to the licence shall be documented.

Option Schedule: Licensing

iii.	All third (3rd) party software licences shall be separately / individually listed.
iv.	Patches and updates shall be available for all licensed software.
v.	Third (3rd) party licenses delivered by the *Supplier* as part of the TPSCM solution shall be managed by the *Supplier*. The *Employer* shall not require entry into additional contracts or agreements to source and manage third (3rd) party licenses.
vi.	The *Employer* retains the right to utilise existing corporate software and hardware licenses and maintenance agreements in adherence to the *Employer's* policies and standards.

Option Schedule: Maintenance Agreement – Standard

vii.	All maintenance agreements to support third (3rd) party software shall be listed separately / individually.
viii.	The *Supplier* shall provide annual maintenance subscriptions to cater for upgrades and patches for hardware and all software, including third (3rd) party software, provided by the supplier.
ix.	The supplier shall identify and provide all licensing required for the identified deployment mechanisms to be used to test all upgrades and patches prior to deployment.
x.	The supplier shall provide an update server that will be used to update all third (3rd) party software during the life of the TPSCM system.
xi.	The supplier shall stipulate all annual license requirements if applicable.

3.2.1.4 Technologies

Requirement Schedule:

i.	The TPSCM system shall use open-source technology where available.
ii.	The system shall comply with the *Employer's* recommended standards for technology, refer to 2.2.

3.2.1.4.1 Operating Systems

The preferred TPSCM system shall be Linux based.

Requirement Schedule:

i.	The TPSCM system shall use Linux as the operating system where possible.
ii.	The deployment of operating system level high availability clusters across the PCC and SCC sites shall be transparent to the user.
iii.	All management and monitoring of the operating system level high availability clusters shall be available from both the PCC and SCC.
iv.	The use of operating system level high availability performance clusters shall not reduce the redundancy required for the TPSCM.
v.	Any group of applications that during operation requires additional disk space, shall be configured on a dedicated disk partition.

3.2.1.4.2 Graphical User Interfaces

The preferred Linux distribution for all Graphical User Interfaces is Ubuntu LTS (Long Term Support). The use of Active X Controls or Java modules is not preferred.

Requirement Schedule:

i.	The TPSCM system shall use Linux, native or hosting, for the Graphical User Interface.
ii.	The Graphical User Interface shall support the use of cross platform open-source standards, such as HTML5.
iii.	Installing multiple versions of any software such as Active X Controls, .Net, DLLs or Java modules shall not result in failures or conflicts in the Graphical User Interface.
iv.	Upon the failure of an operator workstation all functionality shall be transferred – seamlessly, on demand, and without violating any assigned roles and responsibilities – to an alternative workstation in the control room to ensure the continuous operating and control of the Interconnected Power System.
v.	It shall be possible to seamlessly integrate user developed applications into the Graphical User Interface.
vi.	Webserver logs shall be used to identify browser requests and transactions in a consolidated environment. The information from the logs shall be used for fault analysis and management reporting.
vii.	All operator workstation local logs shall be available in a consolidated environment for fault analysis and reporting without any disruption to the user.
viii.	All operator entered functions shall require a double-click or a right-click. No single-click operator action shall be allowed.
ix.	All logs referencing operator entered data shall uniquely identify the user and the physical device where the entry occurred.
x.	The Graphical User Interface on a workstation shall be integrated for all applications of the TPSCM system.
xi.	A single sign-on with role-based authorisation and authentication shall be applicable for workstations in the secure control centres.
xii.	It shall be possible to create a virtual image for the Graphical User Interface with functionality as if the solution was deployed on the native hardware.
xiii.	The compatibility matrix for the Graphical User Interface shall be supported for use of plus and / or minus three (3) releases of the server applications connected to.

xiv.	The upgrade of the Graphical User Interface, for use with an upgraded server application, shall not degrade any installed functionality and operations.
xv.	It shall be possible to save preferred display layouts for operators which can be accessed from the network for the operator workstations.
xvi.	Functionality is required to deliver an authentication mechanism that does not require the user to logout and login. A biometric authentication shall be available for user sign-on and switch-over whilst the GUI maintains full access to the system.
xvii.	The performance monitoring of the web servers shall be available centrally and shall include metrics such as: requests per second; bytes per request; memory, disk and CPU usage; and uptime. No web page errors shall be accepted on the production web servers.

3.2.1.4.2.1 Display Elements

Requirement Schedule:

i.	The toolbar shall be customizable, for example it shall be possible to: • Change the position of different icons; • Change the font and size of the icons on the tool bar; • Add customised menus; and • Edit system menus.
ii.	It shall be possible to customize colours such as the voltage colours centrally.
iii.	It shall be possible to customize the background colour of different application displays as well as the colours to identify different servers centrally. It shall be possible to add a logo or name on the display to identify the application display or server.
iv.	It shall be possible to place notes, text and / or graphics on a display directly or associate the placement with a database item displayed. Entry of the note, text and / or graphic shall be once with the functionality within the TPSCM to ensure redundancy and availability of the entry across all configurations.

3.2.1.4.2.2 Display Functionality

Requirement Schedule:

i.	The system shall have the functionality for the user to search any display by keyword or from an index.
ii.	The system shall have a display which lists all substations including power stations.
iii.	The system shall have a menu which can be used to access the tabular list, equipment group list, tagging menu; operator entered data; inhibited list; not in service list; manually replaced summary; state estimator replaced analogues; mass alarm inhibit ; mass alarm enable; mass alarm restore to service; mass state estimator replace; demand scan related to substation or power station.
iv.	The storage of all notes, text and/or graphical annotations associated with a display shall be consistent across the TPSCM.
v.	Tabular displays shall list the different measurements (status indications, analogues, counters, etc.) at each station. Typical fields shall be list all status indications in a substation (Filter on status indication); list all analogues in a substation (Filter on analogue); substation name; bay name and/or electrical equipment group; device name and measurement type; description of the bay;

	bay status; data quality; functionality to inhibit the alarm and add operator entered data; data item address; capability to access the engineering and raw values for the RTE.
vi.	The system shall have a functionality to sort on all the columns.
vii.	The system shall have functionality for the user to navigate back to the one-line display from the tabular display. The user shall have access to a history of display requests for quick redirecting back to a display.
viii.	The system shall have a functionality to navigate to a different substation tabular.
ix.	The TPSCM system shall have the functionality to automatically refresh the display cache if there are new changes on the system.
x.	Changes to SCADA displays shall be filtered down to other applications like power flow.

3.2.1.4.3 Database Management Systems

Requirement Schedule:

i.	An Application Programming Interface (API) shall enable the building of custom applications for all real-time databases.
ii.	The maintenance and support of all the Database Management Systems shall ensure that the TPSCM is maintained to avoid end-of-life and /or end-of-support components.
iii.	It shall be possible to deploy alternative Database Management System tools to improve first line support and data integrity.
iv.	Preference shall be given to an open-source Relational Database Management System.

3.2.1.4.4 Log Management

Requirement Schedule:

i.	A central Security Information and Event Management (SIEM) shall be used.
ii.	The SIEM shall use open-source technologies.
iii.	All application logs shall be available in the SIEM.
i.	Logs shall be managed to prevent any degradation and / or failure in the TPSCM.
ii.	All failures shall be logged and alarmed as part of the SIEM.
iv.	It shall be possible to include third (3rd) party logs, such as from the operating system, cyber security monitoring software, server and networking equipment logs, into the SIEM.
v.	The SIEM shall support reformatting of logs, Security Event Corrolation, alerting and reporting as a minimum.
vi.	It shall be possible to configure agents throughout the TPSCM for monitoring by the SIEM.

3.2.1.4.5 Virtualisation

Requirement Schedule:

i.	Hosted virtualisation on Linux shall be used for workstations to improve maintenance and security on the workstations.
ii.	No virtualisation shall be used for the production real-time servers.
iii.	Servers required for data modelling and engineering shall be regarded as production servers.
iv.	The Operator Training Simulator shall be considered as part of the production environment.

v.	Native virtualisation can be considered for non-production servers, such as the development and testing environments.
vi.	Where virtualisation is used preference shall be given to open source, such as Kernel-based Virtual Machine.

3.2.1.4.6 Telecommunication

Two (2) independent communication circuits is configured to all remote terminals with limited multi-dropped circuits.

Requirement Schedule:

i.	There shall be no performance degradation where multi-dropped /multiplexed circuits to the RTE at a single substation / power station are used. There shall be a maximum of eight (8) multi-dropped / multiplexed circuits.
ii.	Communication from the TPSCM system to control centres shall be redundant through different routes.
iii.	The WAN for the management and the real-time network between the PCC and SCC shall be physically separate.
iv.	All circuits between control centres shall be regarded as external and non-secure with back-to-back firewalls in each control centre.

3.2.1.4.7 Rear Projection System

The rear projection system structure houses 35 cubes in a 7 x 5 matrix centrally located on the plinth. The gap on either side of the structure is covered with sound absorbing material that matches the *Employer's* standard colour scheme. For the current production system each cube has a 70" diagonal and has 16:9 aspect ratio. The width, height and depth of each projector is 1 550 mm x 872 mm x 625 mm. The total height and width of the map board structure is 10 850 mm x 4 360 mm.

The structure starts approximately 1 140 mm above the plinth so that there is no gap between the ceiling and the top of the structure. The weight of each projector is less than 73 kg. The horizontal screen gap is less than or equal to 2.3 mm. The vertical screen gap is less than or equal to 1.6 mm at 25°C. The angle between each projector is 6 degrees (6°). There are four (4) wall mounted seven segment display meters in the control room installed next to the rear projection system to display system time, time, frequency (hz) and ACE.

Option Schedule: Hardware – Rear Projection System

i.	Open-source technology shall be used for the rear projection system in all control centres.
ii.	Display call-up times for the rear projection system shall be the same as for the workstations even with 3D acceleration enabled.
iii.	The same application used for the GUI on the workstations shall be deployed for the rear projection system.
iv.	Each cube should have as a minimum pixilation of 1 900 x 1 080 pixels that can be upgraded.
v.	The rear projection system shall support real time video feed from a DStv decoder with the capability to scale over four (4) cubes.
i.	A sound system shall be provided for the training simulator room, to allow for the playing back of training videos.

3.2.1.4.8 Front Projection System

The front projection system is used for the training simulators and as an alternative to the rear projection system where there is limited space.

Option Schedule: Hardware – Front Projection System

i.	Open-source technology shall be used for the front projection system in all control centres.
ii.	Display call-up times for the front projection system shall be the same as for the workstations even with 3D acceleration enabled.
iii.	The same application used for the GUI on the workstations shall be deployed for the front projection system.
iv.	A dedicated workstation with the capability to connect up to four (4) projectors shall be allocated to drive the front projection system.
v.	All projectors shall provide ultra-short throw.
vi.	Each projector shall have a minimum pixilation of 1 900 x 1 080 pixels that can be upgraded.
vii.	A sound system shall be provided for the training simulator room, to allow for the playing back of training videos.

3.2.1.4.9 Enterprise Historian

Requirement Schedule:

i.	The TPSCM system shall be able to interface simultaneously to multiple third (3rd) party enterprise historians external to the TPSCM.
ii.	Logical access to information in the TPSCM shall be controlled per user subscription regardless of the technology used for the enterprise historian.

3.2.1.4.10 Webservices

Requirement Schedule:

iii.	Where webservices are used, it shall be required to have a management framework as part of the TPSCM management process.

3.2.1.4.11 Java

Requirement Schedule:

i.	It shall be possible to install alternative versions of Java on a server without breaking any software dependencies in the installed TPSCM or reducing the stability of the TPSCM solution.
ii.	Where application are developed using Java, it shall be required to have a management framework as part of the TPSCM management process.

3.2.1.5 Hardware

The hardware requirement includes all servers, clocks, network equipment (including the breakout panels for the RTE circuits), workstations, the rear projection system and the printers.

Requirement Schedule:

i.	The hardware design specification shall include the calculation of CPU processing, power requirement, memory, I/O requirements, network requirements, short term and long-term storage solutions.
ii.	The computer system design shall comply with the physical redundancy of all hardware. The hardware redundancy shall support data redundancy on the database and file servers.
iii.	A power failure to half the system, where the remaining half automatically takes over all functionality with no effect to the users, shall be a method for failure recovery. This shall be achieved by physically placing all the non-user workstation hardware in two (2) separate computer rooms. The network design shall also include redundancy up to the workstation computers.
iv.	Hardware supplied shall be part of a product range of compatible equipment, to minimise training and maintenance costs. All hardware used shall be supported by local agents.
v.	Redundant colour printers shall be provided in each of the following locations: PCC control room, SCC control room, PCC simulator room, SCC simulator room, PCC operations office and the engineering office.
vi.	Intelligent and programmable power supply strips that include network connectivity shall enable remote management, including the time sequencing of power-on per outlet, of power to all the TPSCM equipment.
vii.	All USB ports shall be disabled on all hardware as the standard configuration. The management to open / enable the USB ports shall be password protected.
viii.	A monitoring system (including environmental statistics) shall be installed and configured, which detects abnormal conditions; provide daily graphs and monthly maintenance reports on the status of the TPSCM, via email and/or SMS.
ix.	The migration of the TPSCM shall be aligned to hardware replacement cycle of the TPSCM.

3.2.1.5.1 Installation and Assembly

Requirement Schedule:

i.	The physical distances between buildings and computer rooms shall be considered during the design and implementation of the TPSCM. The meteorological conditions, i.e., lightning, at the location of these building shall be considered to ensure the reliability of the TPSCM solution. Refer to 0.
ii.	The TPSCM system shall be designed to withstand running at temperatures in excess of forty degrees Celsius (40°C) for a duration of ten (10) days.
iii.	The naming convention for all equipment shall be consistent in the TPSCM. The naming convention and IP addressing shall be defined by the *Employer*. The name shall indicate the type of equipment, function and location for servers, operator workstations and networking equipment.
iv.	There shall be redundant keyboard, video, mouse modules per equipment room dedicated to all equipment in that room.
v.	All TPSCM equipment shall have dual power supplies.

3.2.1.5.2 Lightning Protection

Requirement Schedule:

i.	In light of the high lightning risk area the equipment is located at, lightning protection shall be provided to adequately protect all hardware. The proposed lightning protection equipment may be verified by a third (3rd) party before installation and inspected thereafter.
ii.	Lightning protection devices, suitable for the environment, shall be provided on all galvanic interfaces to the system.

3.2.1.5.3 Test and Development

Requirement Schedule:

i.	It shall be possible to reconfigure a pre-production test and development environment to perform the following tasks: real-time database development; software development and data modelling; front-end development; data acquisition testing and development; patch and software testing and approval; system fault reproduction; and network testing and configuration.

3.2.1.5.4 Network

Requirement Schedule:

i.	The computer system design shall allow for the physical and logical isolation of areas by making use of multiple computer networks. The logical isolation of areas shall support the network layout as defined for the multiple demarcated security zones. Refer to 3.2.1.2.4. Firewalls shall support stateless failover.
ii.	The system shall be able to be configured to a minimum operating and control system with all external connections disabled or disconnected. This shall be achieved with the use of intelligent network devices with filtering and cyber security features.
iii.	The WAN between PCC and SCC shall have dedicated redundant separate links based on functionality, e.g., SCC users hosted from PCC, PCC users hosted from SCC and the inter-site data acquisition communication to the application servers.
iv.	All remote operator workstations shall have WAN access to both the PCC and SCC.
v.	Network serial concentrators attached to the data acquisition servers shall be connected to the telecommunication breakout panels through long length high speed serial splitters. Standard RJ45 connectors and CAT5E cables shall be used to connect to the TPSCM serial data acquisition interface. Standard RS422 with physical DB15 connectors shall be used to connect to telecommunication equipment.
vi.	The interconnections between different buildings and different floors / equipment rooms shall be based on fibre optic links between the switches.
vii.	The interconnections between different buildings and different floors / equipment rooms shall be based on fibre optic, moreover all network connections exiting any room (such as a control room, equipment room or office) or any location with physical separation shall be fibre optic links.
viii.	The network shall be in a fully redundant configuration to maintain availability and meet the performance criteria in the event of a component failure.
ix.	Failure of any single network segment shall not degrade system performance requirements. Thus, the network shall be configured for high availability and shall ensure that any single failure shall not impact performance.

x.	The removal, powering off, or malfunction of equipment connected to the network shall not interfere with operating and control of the power system.
xi.	Inter application communication within and external to a server, shall have dedicated network ports, configurable by the *Employer*. Third (3rd) party software that makes use of commonly known ports shall pass through Intrusion Prevention Systems in-order to perform in-depth analysis of the data frame.
xii.	The TPSCM shall have the functionality for configuration of priorities for quality of service and redundancy at all levels of the network OSI model.
xiii.	The network design and specification shall calculate and document bandwidth requirement for flows between applications, databases, servers and networking equipment for LAN and WAN zones.
xiv.	Network traffic shall remain within a security zone for redundancy communications, example if a HIS needs to update the redundant HIS in the pair; traffic must not be routed via the application server segment / zone.
xv.	It shall be possible to disconnect sections of the network during periods of disturbances. Also, a schematic layout of logical segments of the network split shall be documented.
xvi.	It shall be possible to provide remote maintenance, support and upgrades via a secure network connection in adherence to *Employer* policies and standards.
xvii.	Network cabling shall be provided between the TPSCM system and the telecommunication infrastructure.
xviii.	The network cabling shall be provided, installed and commissioned at both PCC and SCC.

3.2.1.5.5 Servers

Requirement Schedule:

i.	Servers hosting more than one virtual machine shall be of a higher model than servers running a native operating system. For each server hosting more than one virtual machine the hardware specification shall be doubled.
ii.	Redundant database and file servers shall serve as the repositories for shared software, shared data, database definitions, and historical information. The database and file servers shall automatically ensure that critical information is not lost upon failure of any single disk drive.
iii.	Servers running the operating system native without virtualisation or hosting only one guest virtual machine shall have at least two (2) processors, four (4) network adapters, RAID controllers with backup battery configured as at least RAID5 storage, redundant power supplies and an integrated management module offering console redirection.
iv.	Servers hosting multiple virtual machines shall have at least four (4) processors, four (4) network adapters, RAID controllers with backup battery configured as at least RAID5 storage, redundant power supplies and an integrated management module offering console redirection.

3.2.1.5.6 Analysers and Testers

Technologies, such as analysers and testers, are used during the first-line maintenance and support of the TPSCM.

Requirement Schedule:

i.	Six (6) stand-alone protocol analysers, software and hardware, for IEC 60870-5-101, IEC 60870-5-104 and ICCP / IEC 60870-6-503 shall be provided.
ii.	Built-in protocol analysers for IEC 60870-5-101, IEC 60870-5-104 and ICCP / IEC 60870-6-503 shall be provided as part of the data acquisition sub-system. Built-in protocol analysers shall provide a full audit trail of all communication packets processed and the ability to filter out specific messages over a time period using GPS as a reference time.
iii.	Four (4) telecommunication analysers, software and hardware, to verify telecommunication health, for example Bit Error Rate Test (BERT) and Cyclic Redundancy Check (CRC) error detection at physical and data link level shall be provided.
iv.	Four (4) portable computer network cable testers shall be provided.
v.	Two (2) portable fibre optic cable testers shall be provided.

3.2.1.5.7 Spares

Option Schedule: Spares

i.	*Supplier* shall provide a list of recommended spares to support the TPSCM system.

3.2.1.6 Training

Option Schedule: Training

i.	Training shall be provided to ensure the *Employer* can fulfil its responsibility during the project and maintenance phase of the TPSCM.
ii.	All documentation provided during training shall be available online on the TPSCM.
iii.	A detailed list of all the training and the contents thereof shall be provided. Each module shall be priced separately.

3.2.2 Process Requirements

It is expected that the new TPSCM system shall not require any modification to the business processes of the System Operator.

3.2.2.1 Operating and Control

The roles for National Control and Dispatch are:

- Loading operator performs frequency control including managing units on Automatic Generation Control, manages tie-lines against schedule, manages real-time ancillary services, performs generation and load dispatch, and electronic dispatch of generation with full auditability;
- Transmission operator performs outage management;
- Voltage operator manages the voltages and total integrity of the IPS;
- Post dispatch analyst captures and analyses deviations and support dispatch tools;
- Reliability engineer performs real-time risk analysis, analyse quality of supply, dissemination of information on recent power system events, optimisation of the Transmission power network, support dispatch tools and dynamic studies; and

- Power System Managers are responsible for management of the operators and power system risks.

The roles for System Operating and Control are to:

- Act as the interface between the RCC and the PCC;
- Provide detailed instructions for switching to the field personnel;
- Assist all Employer RCCs;
- Perform PCC functions at the SCC site in case of a disaster at PCC site.

Agent System Operating and Control centres have demarcated areas of responsibility for regional lower voltages. The agent System Operating and Control centres have a workstation installed in the remote control centre in addition to having the power network modelled on the local Distribution Management System. In the future there is a possibility of a) a single System Operating and Control centre operating with multiple demarcated regions or b) the current System Operating and Control centre with an additional two (2) System Operating and Control centres distributed across the country to manage the operating and control from KwaZulu-Natal and Western Cape.

The function of Zero Control is to monitor the access to a Transmission substation. The alarms monitored include authorised access via a gate and/or an indication that security has been breached via a fence alarm. Security alarms shall be used for advance alarm processing and risk analysis.

National Management Control provides first line support and analysis of telecommunication circuit faults.

Requirement Schedule:

i.	The TPSCM shall support the multiple operating and control functions defined.
ii.	The configuration of the TPSCM shall support the migration of the System Operating and Control function from agents to centralised models.

3.2.2.2 Economic Dispatch and Unit Commitment

Economic dispatch and unit commitment is done as per the South African Grid Code: The Scheduling and Dispatch Rules.

The day ahead optimisation is done for the next seven (7) days and include the following steps:

- Unit technical parameters, unit availabilities, unit costs, demand side resource information, interconnection schedules and load forecast are transferred from the Generation Information System (GIS) to the unit commitment.
- Unconstrained unit commitment and economic dispatch is determined.
- The Unconstrained schedule is transferred back to the Generation Information System.
- Unit technical parameters, unit availabilities, unit costs, demand side costs, interconnection schedules, load forecast and unconstrained schedule are transferred to the Energy Management System.
- Once the unconstrained schedule is determined, a constrained schedule is determined incorporating network constraints.
- The constrained schedule is transferred to the Generation Information System and the Energy Management System for operating and control.

The intra-day optimisation process is the same as the day ahead, but the horizon is only the current day (instead of 7 days). It is also possible to only execute a constraint schedule without running a new unit commitment first, if appropriate.

The real-time optimisation runs every 5 minutes, looking 15 minutes into the future. It generates an unconstrained schedule and constrained schedule. The constrained schedule optimisation determines the optimal economic dispatch given the current unit output and current loads as determined by the State Estimator, taking into account the Short-Term Load Forecast, network constraints and contingencies.

The Generation Dispatch solution implemented was developed by the *Employer* using PLEXOS® from Energy Exemplar.

Requirement Schedule:

i.	The TPSCM shall support the economic dispatch and unit comment process defined above.
ii.	The economic dispatch and unit commitment functionality shall be delivered as per 3.3.5.

3.2.2.3 Power System Operations

Requirement Schedule:

i.	It shall be possible to import third (3rd) party day-ahead schedules, outages and forecasts using flat files.
ii.	It shall be possible to export power system data from the TPSCM to third (3^{rd}) party software, such as Siemens PSS® and DIgSILENT PowerFactory.
iii.	Versions shall be managed to ensure that exports are maintained from the version deployed during the initial system acceptance testing to newer versions / extension of the CIM/XML, Siemens PSS®, DigSILENT PowerFactory and IEEE data formats.
iv.	Static network model data shall be exportable from the data engineering environment in CIM/XML format.
v.	It shall be possible to import network model data into the data engineering environment from third (3rd) party products.
vi.	Results from TPSCM power system studies shall correspond to the results from offline studies, done by third (3^{rd}) party software, such as Siemens PSS® and DIgSILENT PowerFactory.

3.2.2.4 System Configuration Engineering

3.2.2.4.1 Database Modelling

After the completion of the database modelling, a second database verification and checking is done. This verification is performed by a different person to the one who was capturing data in the master database. The verifier checks the following amongst others:

- all data items that must be mapped are mapped and all the telemetered data items are assigned to the IEC physical address;
- Correct data item names have been used for each data item;
- points are mapped to correct IEC physical addresses;
- correct analogue conversions have been used;
- all control signals have corresponding indications;
- bays that have controllable devices have supervisory indicating switches;
- Ensure that correct model parameters have been set on each control card (digital control/analogue setpoint);
- All input / output data items are linked to the correct RTE; and

- Ensure that the area of responsibility and unique alarm category for each input / output data item is correct.

The verifier is able to do the verification without access to the master database.

Requirement Schedule:

i.	Offline database comparison and verification shall be made possible through the export of the modelling data into comma delimited flat files, enabling the loading of these files into a spreadsheet.

3.2.2.4.2 Commissioning

During commissioning the following checks are done for the data items:

- the correct alarms or indications are received on both the PCC and SCC;
- the alarm state or limit violation is received in red colour;
- the correct analogue value and the direction thereof is received;
- If an analogue received from the station is out of range, ensure that the suspect flag is shown next to the analogue;
- points that are offline show suspect data quality
- the alarm goes to the correct alarm bin / category;
- the audible alarms are received; and
- the correct GPS time stamp is received for the sequence of event (SOE).

All the data items that are available on the database and not available on site during the commissioning is disabled on the production system and removed from the master database before the next database update.

If an error is identified at site and not fixed during the commissioning / test, the data item is marked as not-in-service and tagged. If it is an analogue data item, a State Estimator replaced values is required.

Testing the controls require:

- the use of the operator control pop-up window;
- the confirmation on the one-line display that only the intended device has been selected and is indicated with a yellow circle around the selected device; and
- the test to commence with the control matching the current status of the device.

If any device being tested has a tag attached to it, the current tag is changed to an information tag, in order to allow the issuing of control signals. The tag is reverted to the original state, prior to commissioning / testing, on completion of the control signal test.

Requirement Schedule:

i.	It shall be possible to generate a data sheet for sign-off on all commissioning of SCADA data items.
ii.	All point-to-point testing shall be done to verify that all databases have been deployed and the telecommunication circuit configured to both the PCC and SCC.
iii.	All the commissioning shall be done from workstations situated in the control room at the PCC or SCC.
iv.	The entire substation or power station shall be switched off supervisory for commissioning.

3.2.2.4.3 Fault Investigation

Requirement Schedule:

i.	It shall be possible to change: the deadband for the reporting of analogues; the conversion used for an input analogue value; the low and high value range limits; and the low and high engineering range limit, the IEC physical address and negate the analogue sign on the production system through an incremental update.
ii.	It shall be possible to change: the deadband for the reporting of digitals; the conversion used for an input analogue value; the low and high value range limits; and the low and high engineering range limit, the IEC physical address and negate the analogue sign on the production system through an incremental update.
iii.	A complete audit trail of the incremental update shall be logged.
iv.	It shall be possible to push down the incremental update such as to ensure that the production system remains synchronised with the data and engineering environment.
v.	It shall be possible to roll-back the incremental update on demand.

3.2.2.5 Maintenance and Support

3.2.2.5.1 Migration

Requirement Schedule:

i.	A single data entry and display building master / source shall be used during migration to ensure data integrity and consistency. A process to transform the data for importing into the new TPSCM system for acceptance testing, commissioning and parallel operation shall be provided.
ii.	Scripts and procedures shall be available to update both the systems in parallel from a single data set. These shall also include tags and operator entered data.
iii.	Auditing logs shall be maintained to confirm the integrity of the two data sets.
iv.	Complete separation of the production system and new integration/upgrade system shall be maintained during a system migration or upgrade on site. All data transferred from the production shall be managed with strict access control set by the production system.
v.	An audit trail shall be available in the logs through the standard extended data entry function of the new integration / upgrade system of all real-time data changes from the production system.

3.2.2.5.2 Production

Requirement Schedule:

i.	The supplier shall be able to recreate system and software related problems on the supplier's test system to assist in fault analysis.
ii.	A repository shall be available to download the latest patches and products compatible with TPSCM system in support of a migration path.
iii.	The migration path for the TPSCM system shall be aligned to the support agreement and hardware replacement cycle. The hardware replacement cycle should occur midway through the life cycle of the TPSCM.
iv.	It shall be the responsibility of the *Supplier* to propose a migration strategy to ensure the *Employer* remains on a supported version of the software to enable the deployment of bug fixes.

v.	The migration plan shall be planned and agreed to annually to minimise any disruption to the control room.

3.2.2.5.3 Roles and Responsibilities

Requirement Schedule:

i.	The *Employer* shall be responsible for the end-to-end testing with existing remote terminals and remote control centre partners. Provision shall be made in the project schedule for the required end-to-end testing.
ii.	The *Employer* shall execute the system build and integration from the installation media and procedures supplied by the supplier of the system.
iii.	The *Supplier* shall document all parameters required by the *Employer* to configure the system prior to acceptable testing.
iv.	The *Supplier* shall identify all third (3rd) party licenses required for the installation and support of the system.
v.	The *Supplier* shall provide the installation media as upon agreement with the *Employer* and installation procedure prior to the initial system build on-site. The master copy of the system build shall be available on-site at the PCC and SCC.
vi.	It shall be possible for the *Employer* to resize the system locally and redo a system build without any dependencies on system patches to be delivered.
vii.	The system build environment shall enable the *Employer* to increase the debug and / or log level for analysis and reporting. It shall be possible to add debug statements on an application level.

3.2.2.5.4 Version Control

Requirement Schedule:

i.	Git shall be used as the version control system for tracking changes in all configuration files, source code and databases.
ii.	The *Employer* shall be the custodian of all software sources and configurations deployed as part of the TPSCM. The master storage of the sources and configurations shall reside with the *Employer* at both the PCC and SCC.
iii.	A change control procedure shall ensure that the *Employer's* specific configurations and customisations are retained with software upgrades.

3.2.2.5.5 Backup and Restore

Requirement Schedule:

i.	It shall be possible to do a full image backup remotely from a management network for any server and / or workstation on the system by booting from a separate partition on the selected equipment, as is available through Clonezilla.
ii.	All backups shall be protected through encryption and be access controlled.
iii.	All backups and recovery shall be stored online in the system archives and repositories. The default option for all backups is to be available online.

iv.	No external devices shall be required to be connected to the system during backup and recovery. External devices shall only be used for off-site backups on request. All server backups shall be stored at an off-site location relative to the server.
v.	It is shall be possible to rebuild every server from the original installation media on site. All installation media and procedures shall be saved with version control.
vi.	Backups for all operational data periodically modified to reflect the changes in the power system shall be automated to align with the deployment and commissioning of the data onto the production system.
vii.	All servers shall have an image backup done prior to an upgrade and again before the upgraded server is returned to service.
viii.	All servers shall be configured for dual booting to allow for remote initiation of the backup or restoration of a server.
ix.	The minimum requirement for a server recovery is to restore a backup and redo the latest active database update and / or data transfer to enable the server to be returned to service.
x.	The pre-production system shall be used to test and/or verify the information essential to recovery that is stored on backup media at least annually to ensure that the information is available and the recovery functional.
xi.	It shall be possible to swap out the recovered server into the production environment to evaluate the system as a first-line support function 24x7.
xii.	Image backups of every server, to a dedicated archive environment, shall be hosted at both the PCC and SCC sites.
xiii.	The WAN shall be configured and managed to achieve backups and restoration from alternate sites, i.e., between PCC and SCC.
xiv.	It shall be possible to create backups on external hard drives that can be physically removed off site.
xv.	Six (6) image backups shall be available for all servers on the archive server.

3.2.2.5.6 Maintenance philosophy

Requirement Schedule:

i.	Upgrading of the firewall, intrusion penetration software and networking equipment shall continue during the life cycle of the TPSCM.
ii.	Hosting environments such as for patch management shall be available within the secure TPSCM.
iii.	Connectivity from the TPSCM to the hosting environments at the OEM and / or real-time connectivity to *Suppliers*, including hardware *Suppliers* shall not be open.
iv.	The deployment philosophy and / or scope shall be reviewed annually under advice from the control centres.
v.	Risks associated with changes and upgrades shall be mitigated with documented rollback capabilities.
vi.	Testing and development environments shall be used prior to deployments onto the production system.
vii.	Changes and / or upgrades to software that have specific version dependencies shall be synchronised to minimise the risk of dependency conflicts.
viii.	Special interest groups and problem resolution group meetings shall enable the quick fault investigation and problem resolution.

3.2.3 Cyber Security Requirements

3.2.3.1 Policies and Standards

Cyber security shall be aligned to the requirements from the Cybersecurity Framework from the National Institute of Standards and Technology (NIST) and supplemented by the North American Electric Reliability Corporation (NERC) requirements on critical infrastructure protection and ISO/IEC 27002.

TPSCM shall comply with the following policies and standards:

- 240-55410927: Cyber Security Standard for Operational Technology;
- 32-373: Information Security - IT/OT Remote Access Standard;
- SD-OT/0010001: Security Division Position Paper – Cloud Computing;
- South African Grid Code;
- 240-72942279: EMS and DMS Master Station Computer Disaster Recovery Standard;
- 240-91479924 Cyber Security Configuration Guidelines of Networking Equipment for Operational Technology; and
- 240-82331576: Inter Control Centre Communications Protocol Standard.

Requirement Schedule:

i.	The TPSCM shall comply to the policies and standards defined in 3.2.3.1

3.2.3.2 Technologies

Requirement Schedule:

i.	The flow of data for any anti-virus software upgrades shall be restricted to adjacent zones within the TPSCM and manually controlled.
ii.	The TPSCM shall be monitored for inter zone network intrusions.
i.	Whitelisting shall be installed and configured on all servers and workstations. Whitelisting shall be configured prior to the commencement of the acceptance testing.
iii.	Auditing software shall be configured on the TPSCM.
iv.	No interactive accounts shall be enabled for hardcoded usernames.
v.	Single sign-on and 802.1x with RADIUS server and Kerberos shall be used.

3.2.3.2.1 Remote Access

Requirement Schedule:

i.	Multi-factor authentication (MFA) shall be used for remote access via dual Virtual Private Network (VPN) link to a hardened and monitored jump server located in the isolated DMZ for the remote access solution.
ii.	The TPSCM system shall provide remote access for *Employer* approved users. The TPSCM system shall allow for cyber security specialists to be able manage the granting of system access. All remote access shall be uniquely identifiable and no role-based and/or generic access shall be accepted.

iii.	Remote access users shall first authenticate in a security zone isolated from the production system. All remote access shall be documented against an open action item in the Fault Management System.
iv.	A *Employer* specified secure system shall be used to initiate the access.
v.	The transition from the project to the maintenance / production phase of the TPSCM shall be transparent with regards to the remote access.

3.2.3.2.2 Cloud Computing

Requirement Schedule:

i.	The TPSCM system shall not reside in a cloud but shall be deployed in the dedicated equipment rooms at the Primary Control Centre and the Secondary Control Centre with distributed graphical workstations.
ii.	All data and documentation for the TPSCM system shall be classified confidential and/or higher and shall not be hosted on any public cloud infrastructure.
iii.	Standard documentation from the *Supplier* and not residing within the TPSCM shall not be accessed and referenced from within the TPSCM.
iv.	All information related to the TPSCM system shall be classified as confidential and/or higher and shall be hosted within the same secure perimeter as the TPSCM system itself and stored on *Employer* premises.
v.	No Supervisory Control and Data Acquisition (SCADA) infrastructure or applications shall be hosted in the cloud (public or private). All assets and/or infrastructure for the TPSCM system classified as a critical cyber asset shall be located on *Employer* premises.

3.2.3.2.3 Management

Requirement Schedule:

i.	The replicated update source server shall be installed within the TPSCM system for management and deployment of patches and upgrades.
ii.	The change management for all cyber security modification shall adhere to 240-55410927 Cyber Security Standard for Operational Technology.
iii.	The system shall be able to send alerts with regards to host intrusions and deviations from configured cyber security standards / rules.

3.2.3.2.4 Methodology

The focus of the security architecture shall be to design and implement the following security guidelines:

- Defence in depth: Layered security (i.e., protection mechanisms at multiple levels).
- Hardened platforms: Secure system installation/build.
- Deny by default: Explicit rules required to allow access.

Network-level security shall govern the types of network access allowed among the various security domains with which the TPSCM system can potentially communicate. These requirements shall apply to both the physical and the logical configurations of various network segments.

System (host-level) security shall determine the access allowed among hosts, services, applications, and users in the various security domains that potentially communicate with the TPSCM system. Host and application security measures to achieve the desired results shall be deployed to comply with the Cyber Security policies and standards.

Updates for the anti-virus software shall be certified by the supplier of the TPSCM system on release of an anti-virus update.

A migration path shall ensure that the Operating System's kernel, hardware layer, system library, shells and system utilities remain updated and supported.

All workstations outside a secure control room shall conform to the user authentication, authorisation and accounting policy using radius servers for workstations to authenticate engineering and maintenance users and authorise their access to the requested system or service.

Requirement Schedule:

i.	The network-level and host-level security shall include defence in depth, hardened platforms and deny by default.
ii.	Logical access control shall provide user authentication, authorisation and accounting policy using RADIUS and Kerberos servers for workstations not used in the control rooms.

3.2.3.2.5 Principles

System logical access shall be controlled through five (5) demarcated security zones as seen in Figure 1. The security zones are defined as:

- Restricted zone

The two restricted zones of the TPSCM are highly controlled and the zones contain mission-critical systems or data. These include the real time (blue) EMS, GDS, WAMS, Situational Awareness and Historian. Included in this restricted zone are the simulator, pre-production system, development environment, data acquisition/exchange and GUI. The restricted zone also extends to the DMZ (green) and secure data sources (green).

- Controlled zone

The controlled zone is the *Employer* intranet (yellow) or the any part of the TPSCM network (orange) that is required to access the uncontrolled zone.

- Uncontrolled zone

The uncontrolled zone (red) is public domain, such as the internet or a third (3rd) party service provider's network.

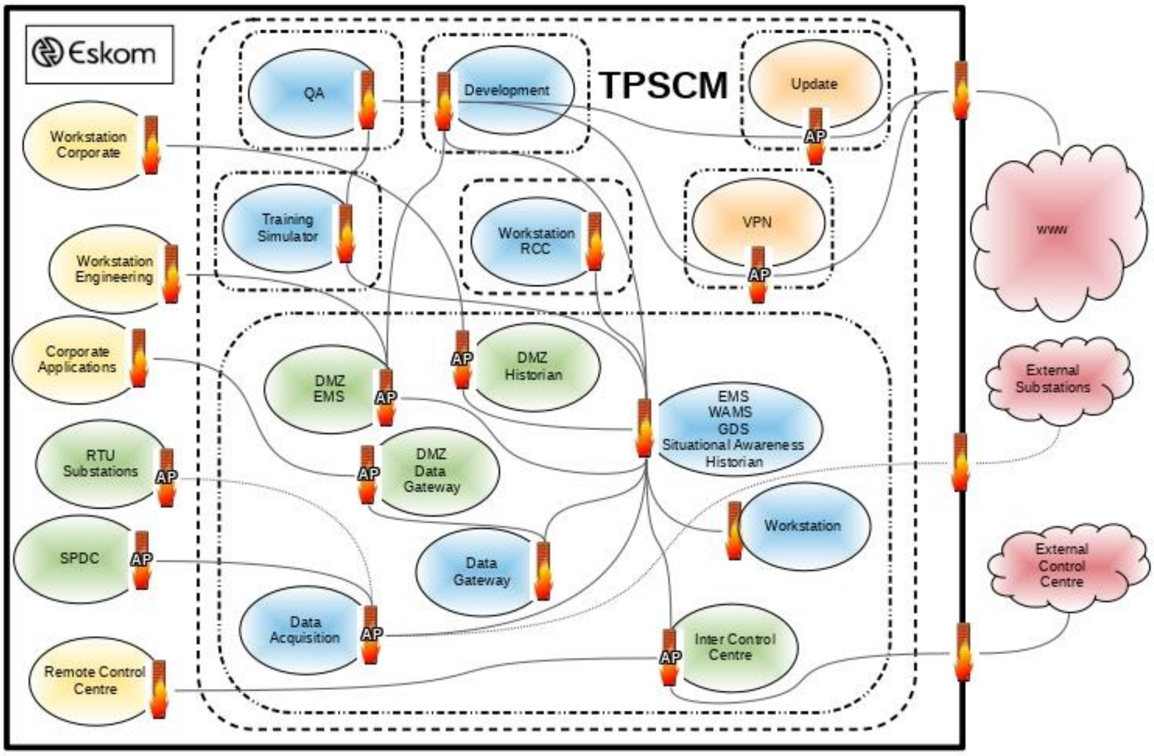

Figure 1: TPSCM Security Zones

Requirement Schedule:

i.	Separate virtual network segmentations shall be defined for the data acquisition servers isolated behind the application servers.
ii.	The workstations in the Primary Control Centre and Secondary Control Centre shall be isolated behind the application servers through virtual network segments.
iii.	Redundant data and source code repositories are required at the Primary Control Centre and Secondary Control Centre. The source code in the repositories shall be identical providing an audit trail for all changes.
iv.	Inter control centre data exchange shall be available from the Primary Control Centre and Secondary Control Centre through a monitored access point.
v.	The primary (at the PCC) and secondary (at the SCC) source for all data items shall be transparent to the operating and control of the power system for any active site. The Inter Control Centre data exchange data shall be configurable as a third data source where available in adherence to all cyber security requirements.
vi.	During migration and parallel operation all data sources shall remain available to the operational Energy Management System for operating and control of the power system. The telemetered data to the new TPSCM system shall be secure with no control capabilities during parallel operations and tuning. Commissioning of the controls on the new TPSCM system shall be restricted to per circuit testing with clear audit logs.
vii.	Only workstations used for the operating and control of the power system shall be on the real-time network segment. All workstations used for offline advanced power network studies and

	monitoring shall be connected to the mirrored TPSCM system in a logical and/or physical demilitarized zone (DMZ) / perimeter subnetwork.
viii.	The TPSCM system shall be segmented into multiple physically isolated cyber security zones defined for the various functionalities. Intrusion prevention modules shall be included within the firewall to inspect traffic between zones. Stand-alone intrusion prevention equipment should be provided on critical network paths on the system. The real-time zone must remain operational with the firewalls powered off. The firewall shall allow for double the number of ports required for the configuration of all zones.
ix.	Firewall connectivity to the corporate network shall consist of two (2) sets of redundant firewalls from two (2) different manufacturers at both PCC and SCC.
x.	Host firewalls shall be implemented on both physical servers as well as virtualised environments. A centralised host firewall management software shall be provided.
xi.	The *Employer*, with the assistance of the supplier, shall do the on-site installation of the TPSCM system in order to verify compliance to cyber security standards.

3.2.4 Testing Requirements

Requirement Schedule:

i.	Use cases for testing shall reflect all business processes required for the operating and control of the IPS and all the processes required for the maintenance and support of the TPSCM system, for example RTE upgrades and new builds.
ii.	Use cases for the business processes defined in 3.2.2 shall be included during the formal acceptance testing.
iii.	Time shall be made available during the acceptance testing schedule for free form tests after each test session.
iv.	There shall be a one-to-one mapping between the acceptance tests and the functional requirements in the specification and the delta design notes.
v.	Any failure during the system integration and acceptance testing shall generate a fault report.
vi.	The performance testing shall be done during the Site Acceptance Testing (SAT).

3.2.5 Operational Requirements

3.2.5.1 Performance Indicators

3.2.5.1.1 Availability

The TPSCM system shall display a 100% availability to workstations in the control centres. Switch over of control between the active and new active site shall be transparent to the users in the control centres. It shall be a single click and pop-up to confirm transition. The TPSCM system shall be regarded as available when no more than 1% of the telemetry is out of scan and with no reduction in quality of the state estimator solution.

Since operation of the power system is dependent on the availability of the TPSCM system, failures of the latter shall be brought to the attention of the maintenance and first line support immediately. Whenever an event or function has automatically or manually been disabled, it shall generate a maintenance notification. In addition, when any device on the system fails, that too shall generate a maintenance notification. The operation of any automatic or manual switchover feature shall be logged and the first line support shall be notified.

The proper operation of communication channels shall be verified on a regular basis by normal use or by test messages on the circuit to verify its operational status. The result of this verification shall be made available to the Network Management Control operator. Each RTE shall have test and maintenance analogues modelled to determine the availability. The analogue could indicate the seconds since midnight per RTE or any other nominated analogue from the RTE.

Availability to the operator of the TPSCM, including both hardware and software, shall be 100% excluding planned interruptions like database updates which shall not exceed 30 seconds per interruption. Database updates can be done at least once a week amounting to 52 interruptions a year. There shall be no performance degradation on the TPSCM even if database updates are not performed for months.

Where feasible, functionality shall be provided through distributed clustered/redundant services. There shall be no requirement for frequent switch-overs and/or restart of systems to maintain the availability of the TPSCM.

Requirement Schedule:

i.	Use cases shall be created as part of the Site Acceptance Testing (SAT) to verify the availability as required in 3.2.5.1.1.
ii.	Management reports shall be available during the defects period of the project to ensure the compliance with the availability requirements defined in 3.2.5.1.1.

Option Schedule: Hardware – Rear Projection System

iii.	The rear projection systems shall deliver a 100% availability through the installation of a redundant hardware architecture up to the display unit.

3.2.5.1.2 Reliability

Failure of any component shall not result in the loss of functions except for those for which the component is directly needed. In particular, failure of a component at one location shall not cause loss of functions at different locations. The failure of any component shall not result in an undetected loss of functions nor multiple and cascading component failures.

The TPSCM system, regardless of the level of activity, shall at all times maintain the minimum specified levels of performance. Activities at all levels shall not cause a TPSCM system failure or produce erroneous results.

Failure recovery for automatically restarting processes or transferring functions from primary hardware resources to secondary hardware resources, when a failure-monitoring function detects a failure, shall always be provided. Failure monitoring functions, which shall be independent of application functions and functional operating modes, shall alarm and log all failures detected.

The TPSCM system shall be designed for fail operative. Any processor shall self-detect its non-recoverable errors and attempt to restart/reboot. Transfer shall be the initial failure recovery approach and restart shall only be used when transfer is unavailable. After a restart, the TPSCM system shall restore itself i.e., no human intervention shall be required, up to a level where it can act as a standby for the current online system, or resume its role in the system, depending on the design and configuration of the TPSCM system. Where secure recovery is not possible, the system shall automatically failover to prevent downtime even if the dual redundant configuration was compromised prior to the failure. No periodic data maintenance shall reduce the redundancy of the real-time active system.

The TPSCM system shall incorporate fail-soft capabilities to handle system activities at levels that exceed the high activity state and conditions. The system shall never fail to process or maintain coherency of inputs obtained from remote inputs, local inputs, and user interface processes.

The TPSCM system shall deploy a selective fail-soft mechanism, by shutting down non-essential functions in order to continue its primary functions at reduced capacity until the fault is corrected. The disabling and shutting down of the non-essential functions shall always generate a maintenance notification, be logged and if automatic recovery is not possible, first line support shall be informed.

Acceptable fail-soft methods include sharing secondary hardware resources or the graceful degradation of certain applications other than data exchange and processing to allow sufficient resources for data processing, control and alarm handling.

First line support shall be notified when a fail-safe incident occurs. The reduced functionality due to the failure shall generate a maintenance notification and be logged. Fail-safe scenarios shall be documented and test procedures shall be available to confirm the safe operations of the TPSCM system after the failure.

The TPSCM system shall be able to with stand regular loss of power, and to automatically restore to operational state without human intervention. Databases must be of such robust nature that they do not corrupt data during the power loss.

Requirement Schedule:

i.	Use cases shall be created as part of the Factory Acceptance Testing (FAT) and Site Acceptance Testing (SAT) to verify the reliability of the TPSCM solution as required in 3.2.5.1.2.
ii.	Management reports shall be available during the defects period of the project to ensure the compliance with the reliability requirements defined in 3.2.5.1.2.

3.2.5.1.3 Response and Recovery Times

Requirement Schedule:

i.	Polling of all RTEs shall be done as soon as a response has been received or at most every five (5) milliseconds, whichever is the fastest. However, the TPSCM system shall be capable of handling response rates of five (5) milliseconds. Reporting of a breaker change of state to all the operator positions (including the rear projection system), from the time the physical plant changes state, shall be less than one (1) second for all conditions, including conditions after a major incident on the power system.
ii.	The display update on the requesting console from the time of the operator’s request shall be less than one (1) seconds for normal and disturbed conditions. Display call-up on the rear projection system shall take less than two (2) seconds and three (3) seconds during normal and disturbed conditions, respectively.
iii.	The detection of a "failed" subsystem on the TPSCM system and the initiation of the automatic fail-over (where applicable) shall be less than five (5) seconds.
iv.	“Cold start” to a fully functional SCADA with advanced network application and Automatic Generation Control (AGC) shall be less than two (2) minutes. “Cold start” to a fully functional system with all servers operational shall be less than five (5) minutes. “Cold start” shall commence after the start of the standard operating system.

3.2.5.1.4 Maintainability

All equipment shall have documented self-tests, diagnostics and troubleshooting procedures to localise any failure or malfunction to the lowest replaceable unit level. Tests and/or breakpoints to facilitate fault isolation, specifically on the communication lines, shall be provided.

The identification, orientation and alignment (including cables and connectors) shall be compatible to the current naming convention and shall be user configurable.

The software monitoring and controlling the application states, such as master/enabled and standby/reserve, shall issue a maintenance notification for any function failure and/or transition. A system monitoring tool shall be installed to:

- Monitor operations for real-time reporting of the performance of the system;

- Diagnose problems such as a website that went down or any other webserver problem, a network failure, and/or reduction in the high availability design of the system;
- Push configuration changes to servers and workstations like the functionality available in Tripwire; and
- Eliminate failures by identifying hardware or software that is experiencing some type of problem on a regular basis and notifying the maintenance and support standby staff to troubleshoot the issue before the failure occurs.

Requirement Schedule:

i.	Computer system monitoring dashboard indicating health, utilisation and performance for management shall be provided as defined 3.2.5.1.4.

3.2.5.1.5 Expandability

Requirement Schedule:

i.	The TPSCM system shall be capable of accommodating any adaptations or extensions of the IPS during its lifetime.
ii.	These changes shall require a minimum reconfiguration of the TPSCM with regards to structure, equipment and software. Furthermore, it shall not degrade the reliability and the availability of the TPSCM system.

Option Schedule: Hardware – Core

iii.	Provision shall be made for additional power supply units, cubicles, sub racks, slots, etc. for these future upgrade requirements.

3.2.5.1.6 CPU Loading

The delivered processing power and main/auxiliary memory sizes of all these computers shall be capable of a 50% field expansion. The delivered configuration shall be capable of performing all required functions and features, under abnormal conditions, without unacceptable response degradation to the operator workstations or loss of the system, using only the main memory on the system.

It is required that a delivered and operational system configuration shall have a five (5) minute averaged CPU loading for six (6) consecutive cycles of less than 45% on any processor during “normal” operating conditions and no process in a wait state.

A ‘normal’ operating condition is defined as:

- 1% of all status indications are changing every hour;
- 1% of all measurands are changing every second;
- Each minute, 0,01% of these measurands are exceeding set limits;
- The operator calls up a new display at a rate of one display per minute and per console;
- The operator sends an open/close breaker control every fifteen (15) minutes;
- Automatic Generation Control (AGC) is run every two (2) seconds;
- State Estimator is run at least every five (5) seconds and on state changes or can be manually triggered to run any time;

- All advanced network applications running as required;
- Real-time trending of hundred (100) analogues, sampled at one (1) second intervals with two (2) hours data displayed and another hundred (100) analogues, sampled at one (1) minute intervals with twenty-four (24) hours data displayed;
- All analogue changes and alarm indications exported to the HIS as per definition for the HIS; and
- A single display routed to be emailed out every fifteen (15) minutes.

During a ‘disturbed’ operating condition, when approximately 33% of all telemetry goes into an alarm state, the five (5) minute averaged CPU loading shall be less than 80% on any processor and no process in a wait state. No response degradation, or response slow down, shall be observed on the operator workstations.

A ‘catastrophic’ operating condition is where the power system has more than 50% of all telemetry in an alarm state; e.g. the system is in a severe under frequency condition and emergency load shedding is taking place. No response degradation, or response slow down, shall be observed on the operator workstations.

In any of the above operating conditions, i.e. ‘normal’, ‘disturbed’, ‘catastrophic’ operating conditions, no computer system shall fail or restart. All operator workstations shall still respond and not freeze or hang up. No power system information or alarm shall be lost or not be annunciated.

Prioritising applications and allocating dedicated hardware such as CPU cores shall be achievable.

Requirement Schedule:

i.	Use cases shall be defined for testing of the CPU loading, defined in 3.2.5.1.6, during the Site Acceptance Testing.

3.2.5.2 Monitoring and Reporting

Requirement Schedule:

i.	Nagios® products or open-source alternatives, such as Zabbix, shall be configured for the monitoring and reporting on critical parameters of applications, networks and server resources.
ii.	Provision shall be made for scalability to take advantage of increasing numbers of cores for multi-threaded software.

3.2.5.3 Documentation

The online documentation search and help facility for both users of the TPSCM and maintenance personnel, should provide the following functionality:

- Record by username who accessed the documentation and the pages referenced;
- Report the most common searched item;
- Include links from the display or application that is being worked on;
- Have a search engine type interface to search for not only key words but phrases;
- Help to include step by step procedures to resolve problems; and
- Allow users to append to existing supplier documents.

Requirement Schedule:

i.	Context sensitive user and operator reference manuals shall be available online for applications and displays.
ii.	Access statistics for online user and operator reference manuals shall be available as per 3.2.5.3.

3.2.5.3.1 Design, Integration and production

The following documentation is required for approval on the system:

- Standard documents of the products;
- Detailed design documents;
- Factory acceptance reports;
- Site acceptance reports after system integration;
- Operator and user manual;
- Standard display reference guide;
- Software installation and maintenance manual;
- Hardware specifications, configuration and cabinet layout for asset management;
- Network design, cabling layout and naming convention report; and
- Migration plan and parallel operations guide.

This documentation shall be delivered in an electronic format and controlled in the version control system.

Requirement Schedule:

i.	All documents listed in 3.2.5.3.1 and required per phase shall be accepted and approved prior to the commencement of the next phase.

3.2.5.3.2 Management Reports

An automated monthly report generator indicating monthly availability of critical system components shall be provided and include at least the following:

- RTE availability;
- PMU availability;
- Data quality appraisal;
- Telecommunications errors;
- Computer availability;
- Computer resource utilisation;
- Computer network utilisation;
- Top ten (10) application users of CPU, memory and I/O;
- Workstation availability;
- Top ten (10) longest display call-up times and times per workstation;
- Audit trail of all Graphical User Interface logins per physical device;
- Control time-outs;
- Workstation display call-up history to indicate specific display the time it was called up and how long it took;
- Telemetry, received via ICCP / IEC 60870-6-503, availability per control centre; and
- Load balancing report per voltage level for each substation.

Requirement Schedule:

i.	All data and statistics shall be available on the system to generate the monthly management reports as defined in 3.2.5.3.2.
ii.	Where feasible these reports shall be generated automatically.
iii.	All management data and reports shall be archived to correspond with the life cycle of the system.

3.2.5.4 Standby and 24x7 Support

Requirement Schedule:

i.	System monitoring tools shall be configured for providing standby or 24x7 support.
ii.	Remote access shall be available to provide standby support.
iii.	All potential critical failures shall be monitored with associated indicators displayed on a system overview dashboard.

3.3 Functional Requirements

3.3.1 System Configuration Management

3.3.1.1 Database Engineering

Requirement Schedule:

i.	A single CIM compliant master database shall be used to configure the power system model and alarming for all SCADA, advanced power system subsystems and generation dispatch applications.
ii.	A change management system shall be used to mark-up changes per project, with a description to the purpose of why it was done, to spot unintended changes and be able to remove them individually
iii.	An automated procedure shall be available to selectively create an update project to include all operator entered and/or changed data from the real-time system into the single master database.
iv.	The deployment of the new database shall be initiated from the production system with a pull of the database from the development environment.
v.	A single-click procedure, with manual activity confirmation, shall be available to update all servers.
vi.	Database verification shall be able to pick up modelling errors. For example, it shall be possible to run a power flow in the database modelling tool against the fully connected network model and security linking.
vii.	The database validation / verification process shall be able to detect duplicate addresses within a substation under the same RTE. Duplication of node numbers for devices in the same substation shall be highlighted / marked-up indicating inconsistent bay structures both graphically in a one-line display and data tables.
viii.	Any database modelling user interface shall support multiple users and configurable views for ease of management.
ix.	The database modelling shall support import from external systems including RTE configurations, ICCP / IEC 60870-6-503 databases, power system models and network parameters from third (3rd) party offline study tools including PSS®E and DIgSILENT.

x.	A single repository shall be used to manage changes to all system configuration databases.
xi.	A CIM/XML export shall be available for all databases to track context sensitive changes in an external change management system.
xii.	Where standard cut-and-paste and/or drag-and-drop functionality is used in the database UI for data entry and/or modification, it is required to verify the changes through a confirmation pop-up stating the nett result before committing.
xiii.	A minimum data validation profile and/or template shall be user definable to ensure that all data is entered prior to database updates.
xiv.	To ensure data integrity during transition, a primary and secondary input/output source for a bay, being upgraded, shall be available, for example node modelling and mapping for the State Estimator and for Generation Dispatch applications.
xv.	A consistent power system model shall be retained even when duplicate equipment is modelled during the refurbishment of the substation telemetry.
xvi.	It shall be possible to merge projects and change management with regards to workspaces.

3.3.1.2 Display Building

Requirement Schedule:

i.	All one-line displays for both the SCADA and Advanced Network Applications shall be linked and stored with the master database.
ii.	Change management shall ensure display integrity and consistency.
iii.	All elements and behaviour on the displays shall be centralised and customisable.
iv.	Modifying the defined core and variable features shall enable the modification of the core features to be replicated to all off-springs.
v.	Overlaying of pictures shall not create a conflict determining context sensitive information.
vi.	Displays shall have layers which can be turned on/off and a modular functionality for better display management.
vii.	Picture placements shall be done with multipliers to ensure snap to grid for positioning of elements according to a layout template.
viii.	All picture elements shall be controlled to avoid the overlay of information, for example tag symbols should not obscure relevant information.
ix.	Changes in the network topology and power network measurements shall automatically be reflected on the display for acceptance, modification or rejection where automatic display generation is enabled.
x.	It shall always be possible to roll-back to a previously approved display layout.
xi.	Automated verification of displays shall be against the master database and shall be able to highlight database changes that require display updates. It shall be possible to identify all relevant displays linked to a device to make sure they are updated.
xii.	Display compilation shall be able to detect errors due to duplicate links, unlinked devices which are telemetered and devices which do not belong to the substation.
xiii.	It shall be able to identify the correct arrow directions for analogues and to detect objects on displays that are clickable but are not linked to any action such as a script.

xiv.	Displays shall be configured to always auto refresh when display information is updated by default. Manual refresh shall not be required but can be used to force a regular display refresh.
xv.	It shall be possible to compile individual displays for each application and bulk compile of displays for all applications.
xvi.	Display compilation shall be able to identify if kV, MVAr and MW measurements exists for both ends of a line. A consolidated line display shall be used to flag planned and active line outages.
xvii.	Secure linking displays shall be automatically created for each substation using the normal state of breakers and isolators.
xviii.	All substation layout displays shall be consistent regardless of the source of the information. It shall be possible to recreate station displays in other applications, for example station one-line displays in SCADA and the advanced network applications.
xix.	It shall be possible to build one-line displays including node numbers which can be optionally displayed.
xx.	Displays shall have tooltip functionality including tags and zooming capability.
xxi.	Tools shall be available to import displays and associated databases into the modelling environment from third (3rd) party products.
xxii.	All data used for power network applications and operating and control on the one-line displays shall be user selectable and/or layered to limit the clutter during automated display building.
xxiii.	It shall be possible to create a display directory for the displays in any application.
xxiv.	It shall be possible to create additional navigational links on any display.

3.3.1.2.1 Display Elements

Requirement Schedule:

i.	The toolbar shall be customizable, for example it shall be possible to: • Change the position of different icons; • Change the font and size of the icons on the tool bar; • Add customised menus; and • Edit system menus.
ii.	It shall be possible to customize colours such as the voltage colours centrally.
iii.	It shall be possible to customize the background colour of different application displays as well as the colours to identify different servers centrally. It shall be possible to add a logo or name on the display to identify the application display or server.
iv.	It shall be possible to place notes, text and / or graphics on a display directly or associate the placement with a database item displayed. Entry of the note, text and / or graphic shall be once with the functionality within the TPSCM to ensure redundancy and availability of the entry across all configurations.

3.3.1.2.2 Display Functionality

Requirement Schedule:

i.	The system shall have the functionality for the user to search any display by keyword or from an index.
ii.	The system shall have a display which lists all substations including power stations.
iii.	The system shall have a menu which can be used to access the tabular list, equipment group list, tagging menu; operator entered data; inhibited list; not in service list; manually replaced summary; state estimator replaced analogues; mass alarm inhibit ; mass alarm enable; mass alarm restore to service; mass state estimator replace; demand scan related to substation or power station.
iv.	The storage of all notes, text and/or graphical annotations associated with a display shall be consistent across the TPSCM.
v.	Tabular displays shall list the different measurements (status indications, analogues, counters, etc.) at each station. Typical fields shall be list all status indications in a substation (Filter on status indication); list all analogues in a substation (Filter on analogue); substation name; bay name and/or electrical equipment group; device name and measurement type; description of the bay; bay status; data quality; functionality to inhibit the alarm and add operator entered data; data item address; capability to access the engineering and raw values for the RTE.
vi.	The system shall have a functionality to sort on all the columns.
vii.	The system shall have functionality for the user to navigate back to the one-line display from the tabular display. The user shall have access to a history of display requests for quick redirecting back to a display.
viii.	The system shall have a functionality to navigate to a different substation tabular.
ix.	The TPSCM system shall have the functionality to automatically refresh the display cache if there are new changes on the system.
x.	Changes to SCADA displays shall be filtered down to other applications like power flow.

3.3.1.3 Change Management

Requirement Schedule:

i.	A CIM/XML export of the database, stored as an online backup of the latest deployed database, shall be created as part of a full / destructive database deployment.
ii.	The change management system shall document the incremental change between the versions of the production database.
iii.	All one-line displays shall be stored as part of the update set.
iv.	Before deploying the database and displays to the production system, automated and/or manual checking and reporting shall be available for database and displays coherency, correct acquisition of real time data, and accuracy of conversions and calculated data.

3.3.2 Graphical User Interface

Requirement Schedule:

i.	All workstations shall provide an integrated Graphical User Interface for the TPSCM.
ii.	It shall be possible to call up displays in a predefined target pane and/or window.

3.3.2.1 Situational Awareness and Analytics

The Situational Awareness and Analytics provide, via a single platform, multiple views of the power system state that allows the combination of data between different types of data sources. This enables reasoning about the current conditions and alerts the control staff of potential threats such as weather, fire or lightning, which affects the state of the power system or those working on it, such as live line teams and maintenance staff etc.

The analytics use the EMS and/or WAMS information (e.g., State Estimator, Contingency Analysis, Dynamic Stability Assessment and Short Circuit Analysis) to link the consequences of known threats to the power system and notify control staff of any potential threats, within the next hour

The communication links between the visualisation server and all the data sources include but are not to be limited to:

- Energy Management System applications such as the Advanced Network Applications;
- Results from the Wide Area Management System analytics;
- Automatic Fault Analysis;
- Advanced Fire Information System;
- Lightning Locator System;
- Weather data;
- Spatial information for Transmission;
- Distribution Management System and/or Advanced Distribution Management System;
- Transformers oil dissolved gas information from the Dissolved Gas Analyser (DGA) Kelman System;
- Transmission enterprise database;
- TPSCM operational historian;
- Travelling Wave System; and
- Substation automation and/or engineering server.

Requirement Schedule:

i.	All workstations shall have an integrated Situational Awareness and Graphical User Interface.
ii.	The TPSCM shall provide the control staff with a graphical interface on which they can see the relationship between the different data sources, listed above, and the power system.
iii.	All information displayed on the Graphical User Interface from the Situational Awareness shall be available on the rear projection system.
iv.	It shall be possible to manage data to ensure a time consistent view of the power system. There are two types of data: static data refers to power system objects; and dynamic data refers to power system threats.
v.	All displays shall allow for the ability to scroll up and down or left and right in order to view all parts of the scene under display, even though the magnification is too large to view the entire scene without scrolling.

3.3.2.1.1 Analytics

Requirement Schedule:

i.	A national map of South Africa shall be visualised, with the IPS objects and environmental threats populated with a zoom in and out functionality to adjust the magnification of the display.
ii.	It shall be possible to navigate from a Situational Awareness environment to a substation one-line display, by clicking on the substation and vice versa.
iii.	A display of the complete network model shall be available with the functionality to zoom into individual one-line displays. Tie-line displays for regions within the IPS and Southern African Power Pool shall be available.
iv.	It shall be possible to overlay the results from the advanced network application on a consistent view of the power system available from the Situational Awareness.
v.	It shall be possible to view weather trends as graphs for forecasted and real-time weather trends. The display shall clearly indicate the timeline of the data: past (has already occurred); present moment (real-time) and future (is anticipated to occur over a 24-hour period) using forecasted weather data.
vi.	It shall be possible to visualise objects on the IPS which are in and out of service (can they transmit or not) in relation to IPS (lines, substations). Thus, it shall be possible to integrate the outages in the power system in the risk assessments. All outages in the outage schedule that are booked for each day shall be visualised on the visualisation system, i.e. actual or planned for the day at a specific time; and outages in progress or booked for the day.
vii.	The health analysis of a transformer object shall include transformer oil gas levels to assess the distribution of these gases to relate it to a potential electrical fault, and the rate of gas generation to indicate the severity of the fault; and transformer windings temperature to monitor the rise in transformer temperature.
viii.	The layout of a group of displays called up regularly should be saved centrally or locally on the workstation for later reference.
ix.	Geographically accurate representation of the impact of external forces such as meteorological conditions and changes in the inter-regional transfer limits on the total renewable contribution in terms of active and reactive power shall be provided.
x.	Geographically accurate representation of the impact of external forces such as meteorological conditions and changes in the Southern African Power Pool (SAPP) network in terms of active and reactive power shall be provided.

Option Schedule: Situational Awareness

i.	It shall be possible to calculate the risk of power lines tripping due to fire within 15 minutes to an hour before a potential trip. The algorithm to calculate the risk shall take the following into consideration: air temperature around a line using the line GPS coordinates and the weather information GPS coordinates; humidity (amount of water vapour in the air); wind speed and wind direction; and vegetation (e.g., grass). The calculation shall consider that the faster the wind speed, the longer the grass, the stronger the wind direction, the warmer the air temperature and the higher the humidity around the line the higher the probability of the line tripping.
ii.	It shall be possible to manage the conditions / rules associated with the risk / threat to a power system object. The structure of the rules shall indicate the conditions and/or risks which may lead to a known outcome. As an example, long grass in a dry area with a fire burning under a line will pose a higher risk of tripping of that particular line. But, if the same line had fire burning under it in a rainy season after grass cutting has taken place, the outcome shall be different.

iii.	Data / alarm exchange between the TPSCM and the Automatic Fault Analysis System (AFAS) shall enhance the fault analysis on the power system.
iv.	The Situational Awareness tools shall propose a mitigation strategy and present it graphically to the operator.
v.	The same application used for the GUI on the workstations shall be deployed for the rear projection system.

3.3.2.1.2 Alarms and Notifications

Requirement Schedule:

i.	Environmental threats shall include for example symbols representing a fire or lightning threat in the vicinity of the power system. Clicking on each of the warning symbols, the system shall provide a drill down facility to the exact position / geographic location of the threat in relation to the power system and other related information.
ii.	The transformer bay shall flash or be highlighted for transformer risks / threats such as overheating. The Situational Awareness system shall allow the bay to be examined with additional information, such as transformer temperature and transformer oil data, on demand.
iii.	It shall be possible to notify control centres geographically of power system threats due to fires, storms, lightning, snow and fog in the form of an alarm on the local workstation and/or rear projection system. The lines' location shall be displayed in relation to its physical location.
iv.	An alarm shall exist in the form of a threat (an alarm condition which needs attention); or warning (additional information that is available about the network) which is dependent on the abnormal conditions when the system thresholds are exceeded.
v.	It shall be possible to configure any alarm generated in the Situational Awareness as audible, based on roles and responsibilities of the user.
vi.	It shall be possible to manage a list of people to receive notifications by interpreting alarms. The type of notification (warning/alarm) received by an individual will depend on their role or the geographical area. For example, the notification received by managers will differ from the one received by field staff.
vii.	The alarm categories shall include: o Health – customer supply is unhealthy as reported by study programs; o Threat – abnormal conditions reported by Wide Area Monitoring System, Contingency Analysis (MVA overload), Short Circuit Analysis (Fault level exceeded), Power Flow (Future load exceeded) and risk conditions from lightning storms or grass fires approaching; and o Information – additional information is available, i.e., the object has detected an alarm condition that needs attention.

3.3.2.2 Data and Display Development

The data and display engineering function is a critical requirement to the reliable operating and control of the Interconnected Power System. The Data and Display Development is thus considered part of the production environment.

Requirement Schedule:

i.	Checks shall be available to confirm that the placement of control picture / pop-up, on any display, has not inadvertently been duplicated.

Option Schedule: Generation Dispatch System – Integration

i.	It shall be possible to import and export incremental change documents to the data and models in the Data and Display Modelling System for data defined in 3.3.5.4 and 3.3.5.5.
ii.	The TPSCM shall provide the master source for data and display engineering.

3.3.2.3 Energy Management System

3.3.2.3.1 Supervisory Controls

Requirement Schedule:

i.	All operating and control processes shall allow for an operating and check role from the other operators. A status indication or analogue selected for supervisory control shall be indicated as such on all displays on which the selected status indication or analogue is displayed for the duration that the control process is active.
ii.	The system shall support the following functions: two-state device control, such as circuit breakers, motors, etc.; single-state device control, such as AGC up or down; setpoint device control, such as generators, loads, hydro excitation, and Static VAr Compensator (SVC) gain; incremental device control, such as tap changers; control sequences; and six state devices, such as auto-reclose relays.
iii.	It shall be possible to identify the secure linked state of a substation.
iv.	It shall be possible to restore the power network to the secure linked state as defined in the operating guidelines and configured in the database. The TPSCM system shall have capabilities to identify the discrepancies.
v.	Control commands shall be accomplished by making control requests to the RTEs. A supervisory control command shall be sent to a RTE only after the control request has been checked for validity such as control tag status, deactivated status, area of responsibility, etc. Invalid control requests by the operator shall be rejected and logged.
vi.	Control activity, shall as a minimum, require mouse repositioning between control function select and operate.
vii.	Validity checking shall include testing of individual and / or combinations of SCADA data items before authorising the supervisory control. The supervisory control dialogue window shall indicate if any unacknowledged alarms are existing for this data item and / or bay, and if there are attached notes on the data item and / or bay.
viii.	Malfunctions including RTE ‘no response’,‘ communication error’ and ‘check-back-verify error’ on control selection shall be reported as diagnostic messages.
ix.	Selected control operations shall be checked for completion and logged. A ‘device failure’ shall not cause any automatic control retry.
x.	The change of status of a device, which results directly from supervisory control by the operator on that particular device, shall not cause a change-of-status alarm but shall be logged as an event. The user and workstation of the originator issuing the control shall be included in the event log.
xi.	It shall be possible to have controls with or without control timeouts, and functionality to change the control timeout period per control where required.
xii.	A forced telemetry refresh to update the status of the control device and/or bay shall be user configurable.
xiii.	It shall be possible to report on stale analogs that did not change over a specific time period. This period should be user definable.

xiv.	At any time during the execution of a list of predefined control sequences, the operator shall be able to stop further execution via a cancel feature, as well as bypass selected list items. In addition, telemetry and control permissive checks shall be incorporated in the sequence with operator override capability.
xv.	The modelling and operating of controls shall be consistent for all controls in the TPSCM even those associated with a non-telemetered status indication and / or status indication not being updated via telemetry but where the feedback analogue is scanning and being updated.
xvi.	In addition to the device control such as a control command, raise and / or lower command and setpoint control a 32-bit command string required for AGC shall be implemented.

3.3.2.3.2 Interlocking on Supervisory Control Sequences

Requirement Schedule:

i.	The interlocking shall also provide a means to check activity within a fixed and relative time period, e.g., only after a specified time or only during a defined time period. It shall be possible to override the interlocking following acknowledgement of the interlocking message which shall also be logged, for example: for parallel lines, ensure that the remote end breaker on the alternate line is not already open; and preventing the opening of an isolator when the line is still carrying load.
ii.	Provision shall be made to override the described interlocking functionality on demand.
iii.	It shall be possible to set up generic rules, based on the bay under supervisory control, to interrogate specified status and analogue conditions associated with the controlled status indication or analogue before allowing the control to be issued.
iv.	Suppression of alarms shall include a forced, user enterable, timer to ensure that the bay or device has a timeout feature where alarms will not be suppressed. The same features must apply for inhibit functionality.
v.	A global flag shall be made available for operators to select when the system is undergoing stressed conditions, allowing to by-pass automatically the interlock and associated tags tests in the control authorisation checks.
vi.	The option to bypass an interlock or to create a new user definable interlock shall be restricted to permissible and authorised users.

3.3.2.3.3 Bay States

At minimum bay states shall be defined for electrical elements/devices such as:

- Disconnected: all isolators are open (breaker state shall not be considered);
- Isolated: bus isolators are closed and line isolators are open;
- Connected: isolators are closed and the breaker is open;
- Dead: isolators and the breaker is closed and kV <= 0;
- Energized: isolators and the breaker is closed and kV > 0;
- On load: isolators and the breaker is closed and MW > 0;
- Bypass: bypass isolator is closed and line isolator is open;
- MVAr only: isolators and the breaker is closed and MW = 0 and MVAr > 0;
- Earthed: One or more of the earth switches are connected; and

- Unknown: telemetry from the bay analogues is in conflict with the breaker and isolator statuses.

Requirement Schedule:

i.	The bay model shall group all the devices in a substation according to the bay that the device is part of and group all substations into regions. The current bay state shall be available for use in alarm and display processing.
ii.	When the bay processor is disconnected or isolated from the busbars the extent of the alarm processing shall be configurable.
iii.	A composite object shall define a hierarchical construct of a set of numerous objects and / or data items.
iv.	It shall be possible to visualise the presence and extent of alarm and abnormal conditions from equipment level through the bay and / or composite object level up to the system level.
v.	SCADA functionality that shall be available per bay and / or composite object include alarm counters; unacknowledged alarm indication; tabular displays; alarm inhibit or not-in-service commands; tagging; control interlock; and topology processing.
vi.	A pop-up display per bay and / or composite object shall be available for operating and control.
vii.	One-line displays shall clearly indicate the condition of the suppression of alarms of all devices linked to a bay and / or composite object.
viii.	Calculation of the bay states shall indicate electrical safety of the electrical elements / devices such as ‘Bypass’, ‘On Load’, ‘Energized’, ‘Isolated’, ‘Connected’, ‘Disconnected’ and ‘Unknown’. The state of the bay shall be recalculated following any breaker or isolator change.
ix.	The state of the bay as defined above in 3.3.2.3.3 shall be identifiable.

3.3.2.3.4 AGC displays

Requirement Schedule:

i.	Unit level AGC displays shall include the functionality to define derations / loadlosses including start and end times or derations / loadlosses on their own. The capacity and limits shall be reduced based on the declared derations / loadlosses. The functionality shall exist to import derations / loadlosses with start and end times from external systems for comparison.
ii.	The functionality shall exist to switch on all units on AGC, which are selected for AGC at the power stations.
iii.	Breaker statuses from the low voltage side of the generators shall be displayed on unit status displays and plant status displays.
iv.	Displays sorted on generation types shall be available.
v.	Unit status displays shall include the ability to indicate reserves available to pick up to maximum capacity for peak dispatch as well as reserves available to deload to minimum generation, for example during night minimum. Unit status displays shall also indicate excess generation to reflect the inability to deload to minimum generation.
vi.	The displayed reserve calculation shall have the functionality to exclude generators when synchronising to the grid and when generating under minimum generation.
vii.	The functionality shall exist on displays to include / exclude generation types in total generation, load, capacity and reserve calculations. This functionality shall also be extended to include / exclude generation based on mode, for example the SCO, offline and pump modes for pumped storage units.
viii.	It shall be possible to generate a display based on any defined state in the database.

3.3.2.4 Generation Dispatch System

Requirement Schedule:

i.	A Graphical User Interface on the same workstation used for the Energy Management System shall be used to interface with the GDS.
ii.	The user interface shall allow for all user input required in the Generation Dispatch System.

3.3.2.5 Wide Area Monitoring System

Requirement Schedule:

i.	All control centre and engineering workstations connected to the control network shall be able to access the Wide Area Monitoring System displays. The user-based access control shall be consistent across the TPSCM system.
ii.	Multi-panel displays with one-line displays, geographic layout displays, textual visuals with navigational tools capabilities and colour coded visual alarms shall be supported.
iii.	A user configurable summary display/dashboard shall provide real-time situational information metrics across the IPS using integrated information in a common centralised display.
iv.	Simplistic type visuals and gauges shall be used to provide information on a set of predefined metrics that characterise the overall status of the IPS. Information from metrics such as relative angles, voltage magnitudes, phase angles, system frequency and power flows on critical corridors from PMUs spanning the geographic region shall be available.
v.	Metrics, information from other synchronised measurements technologies such as Small Signal Stability Monitoring and information for user selected PMUs shall also be configurable for display.
vi.	Angle measurements from PMUs shall be available on any display in the TPSCM.
vii.	Online reports with trends showing long term trends and statistics on voltage magnitude, angles, angle difference, real and reactive power flows as well as frequency profiles for user selected PMUs shall be available. Hourly and daily reports shall also be available for viewing.
viii.	Online reports with trends showing long term trends and statistics from other synchronised measurement application metrics shall be available.
ix.	The input data used for displays shall be selectable from the real-time synchronised phasor database or translation database (if required) from other Synchronised Measurements Technology applications.
x.	The GUI shall allow the operator an easy and quick assessment of the following system conditions: • High and low voltage regions within the grid; • Monitored angles relative to a specific reference; • System and local frequency to assess system coherency and dynamic stress under operating conditions; • Actual real and reactive power flows in key corridors to track flows with respect to predefined thresholds; and • Metrics from other synchronised measurements technologies i.e., ‘damping ratio’ from a Small Signal Stability application which will alert the operator that the system is close to instability.

3.3.2.6 Operator Training Simulator

Requirement Schedule:

i.	The Graphical User Interface on the simulator shall be Identical to real-time system.
ii.	The instructor shall be able to use any user workstation allocated with simulator access rights, normally the instructor console, to set up and control the training session, and interface with the trainee at the trainee console.
iii.	Functionality shall be available to edit and create training cases for the definition and modification of training sequences and events as well as to re-execute a particular training sequence.
iv.	Audible tones for alarms on the simulator shall be identical to those of the real time system.
v.	The simulator shall be closely integrated with the operational system, with identical databases and displays.
vi.	Simulator training rooms at the PCC and the SCC, where physical possible, shall have identical look and feel as the PCC / SCC control room, including rear projection system, OTS driven LED display systems and the same number and size of monitors.
vii.	Simulator training rooms shall have displays indicating GPS time, time difference and frequency like the PCC / SCC control rooms.
viii.	It shall be possible to export scenarios or replay cases from the Operational System on the OTS. Also, it shall be possible to save power system layouts including databases and displays with the scenarios or replay snapshots. Replaying events that occurred previously on a power system that has changed versus replaying an event from the current configuration shall be the same to the instructor.
ix.	It shall be possible to alter the time incremental step to slower than real-time or to fast forward the simulator time.
x.	There shall be a simulator in the DMZ environment that will allow operators to use the OTS through the IT network when connecting remotely. From corporate or production network it shall be possible to isolate the simulator from the DMZ allowing for re-configuration.

3.3.3 Operator Training Simulator

The Operator Training Simulator (OTS) is required for the following major tasks:

- Training and formal accreditation with respect to power system operation;
- Review of normal, disturbed and black-start conditions and power system restoration;
- Review of voltage regulation, loading and dispatch;
- Training with respect to power system operation under market conditions; and
- Training of employees from external utilities.

Requirement Schedule:

i.	The simulator shall mimic the Energy Management System, Generation Dispatch and Wide Area Monitoring System, Situational Awareness functionalities in terms of “look and feel” as closely as possible.
ii.	Identical use, as on the –real-time system, of the operator workstations shall be provided.
iii.	A dynamic OTS shall be provided encompassing the dynamic stability tools and WAMS.

iv.	The OTS shall have at least a one (1) second frequency update cycle.
v.	The OTS shall provide exports, such as logs, reports, saved cases and session replays, from the simulations for post analysis/replay and/or comparison with pre-defined trends and training evaluation.
vi.	The OTS shall be used to control the power system network when it is not possible to control the power system any longer from inside the PCC or SCC control room.

3.3.3.1 Structure of the Simulator

The simulator shall cater for the following power system sizing.

- Ten (10) Automatic Generation Control areas;
- Hundred (100) islands;
- Unlimited generation companies;
- Unlimited busbars;
- Unlimited power system devices (lines, capacitors, reactors, breakers, SVC's)
- Unlimited generators;
- Unlimited loads; and
- Load curves as per the Power System Model Adaptation.

Requirement Schedule:

i.	It shall be possible to size and/or resize the OTS to meet the requirements defined in 3.3.3.1.

3.3.3.2 Simulator Modelling

3.3.3.2.1 Modelling of the Power System

A standard Operator Training Simulator shall be provided, with models to cater for all the devices on the *Employer* power network:

- AC transmission lines;
- DC transmission lines;
- Bipolar and monopolar HVDC operation;
- DC / AC and AC / DC converters;
- Injections (generators, connection to foreign power systems);
- Generation detailed models for steam, hydro, pump storage, gas turbines, nuclear and renewable models such as photovoltaic, wind, concentrated solar power and battery storage, including electric vehicles;
- Capacitive devices used as voltage dividers for supplying load;
- Conforming and non-conforming loads;
- Flexible AC transmission system (FACTS) devices including SVCs, STATCOMS, series capacitors, line reactors, shunt capacitors, shunt reactors;
- Pump storage schemes, such as Synchronised Condenser Operation (SCO), pump, generate, SCO pump, and SCO generate;

- Peaking plant behaviour;
- Special protections schemes;
- Transformer tapping, both manual and automatic as well as ‘master-follower’;
- Load variation for local and power system wide influences; and
- SCO mode for gas turbines including open cycle gas turbines.

Requirement Schedule:

i.	The OTS shall have standard and/or equivalent models to cater for all the devices defined in 3.3.3.2.1.
ii.	All models shall be based on international standards defined by IEEE/IEC/EPRI/Cigre and include sufficient detail to enable the simulator to emulate the live power system as near as possible to actual behaviour.
iii.	The SVC models shall allow for the automatic opening and closing of capacitor and reactor breakers remote from the SVC installation as well as all the functionality to control the i) kV setpoint; ii) Q control setpoint; and iii) slope and gain.
iv.	The pump storage models shall completely integrate with the various user definable settings currently available on the online system including speed and excitation setpoints. Pump storage models shall allow for the dynamic movement of generators to any mode of operation.

3.3.3.2.2 Modelling of the Control System

Requirement Schedule:

i.	The modelling of the control system shall provide for the protection relays such as voltage, frequency, over-current, dead bus, earth fault, synch check and reclose.
ii.	The following standard relay models shall be provided: voltage relays (high and low); frequency relays (high and low); over-current relays (inverse time) and re-closure schedules; synchronisation relays; generic under frequency relays; impedance relays; and out-of-step relays.
iii.	It shall be possible to include power system control systems such as re-closure schemes; protection and remedial action schemes in the simulator training.
iv.	Modelling for distributed energy sources and/or negative loads shall be available.
v.	Multiple area AGC including interchange scheduling and interchange control, i.e. Tie Line Bias Control, Constant Frequency Control, shall be provided.
vi.	Load shedding such as under frequency load shedding, load curtailment, etc. shall be modelled.
vii.	Provision shall be made to include battery storage in the models for both generation and load control.
viii.	Algorithms for all substation based operator activity, external to the modelling of the power system, shall be defined, e.g., the startup or shutdown of a hydro generator, the change of output for the battery storage and renewable generation management from the operator workstations.

3.3.3.2.3 Modelling of the Energy Management System

Requirement Schedule:

i.	The simulator shall mimic the real-time EMS and shall include SCADA applications and advanced network applications, such as power system security analysis functions, in a multi-control centre environment.

3.3.3.2.4 Modelling of the Wide Area Monitoring System

Requirement Schedule:

i.	The simulator shall allow for the import of measurements from the Wide Area Monitoring historian for a modelled scenario.
ii.	It shall be possible to augment the power system time step with information from the WAMS.

3.3.3.2.5 Modelling of the Generation Dispatch

Requirement Schedule:

i.	The simulator shall emulate all generation dispatch related functions.
ii.	It shall be possible to import results from the production GDS as part of the training session.
iii.	It shall be possible to include a copy of a previously saved result from the GDS in the training session.

Option Schedule: Generation Dispatch System – Integration

iv.	The integration of the Generation Dispatch System into the TPSCM training environment shall produce the same results as the production environment.

Option Schedule: Generation Dispatch System – Replacement

v.	The Generation Dispatch System installed in the TPSCM training environment shall produce the same results as the production environment.

3.3.3.3 Simulation Control

Requirement Schedule:

i.	It shall be possible to record and playback training sessions. Complete audit trails shall be kept for replay and analysis of a given training session. The archived log and replay files of a given session shall be saved for this purpose, and an extract of the simulator message logs shall be exported and stored as an audit trail for each session.
ii.	It shall be possible to initialise a simulation from any point in the playback session.

3.3.3.4 Substation SCADA Behaviour

Requirement Schedule:

i.	Provision shall be made to enable the modelling of supporting substation SCADA behaviour external to the electrical model used by the simulator. This facility shall provide both tools and generic routines that can be linked to specific bay processor behaviour from the specified SCADA data items.
ii.	Where required, substation behaviour shall be modelled via conditional events (e.g. interlock substation logic). The simulator shall have capabilities to model: parallel transformers gang control; and pump storage modes.
iii.	Provision shall be made to cater for time delayed specified sequence of event changes to both status and analogue SCADA values to enable the realistic modelling of actual substation SCADA behaviour. Where possible, this behaviour shall be modelled via conditional events.
iv.	The standard simulator shall include the simulation of noise, dead-band and offset of SCADA measurements.
v.	It shall be possible to define communication delays for data acquisition and controls.

3.3.3.5 Import / Export

Requirement Schedule:

i.	A facility shall be provided to allow a real-time or historical snapshot of the power system to be imported into the simulator for playback and study.
ii.	Once the imported file has been loaded into the simulator, an absolute minimum of manual configuration shall be required to start the simulation.
iii.	If input files are generated from a snapshot, i.e. from the real-time Energy Management System or a power flow study of the power system, a facility shall be provided to recreate the events automatically as time base and/or conditional events to build a training scenario.
iv.	Manual (single step) or automatic (playback mode) reconstruction of past states shall be supported. This facility shall include the ability to change the replay speed.
v.	It shall be possible to export to other power system analysis software such as DigSILENT PowerFactory and PSS®E.
vi.	It shall be possible to initialise the simulator from the historian or from real-time snapshots, power system studies or previous simulation sessions.
vii.	Export to other sources shall be supported in the following standard and propriety formats: PSS®E, DigSiLENT PowerFactory and IEEE.

3.3.3.6 Load Modelling

Requirement Schedule:

i.	Facilities shall be provided to simulate the changes in the load patterns of the power system by implementing a number of load curves. All loads shall be definable to one or more load curve simultaneously.
ii.	The load configuration shall be dynamic and not require a regeneration of a simulation.
iii.	It shall be possible to change MW and MVAR values of loads on the one-line display.

iv.	All load curves/schedules used by the simulator shall be automatically updated to be in sync with the real-time system load when the simulator is updated
v.	It shall be possible to configure and modify all loads in the simulator individually, by load area and by changing the total power system load. The change of the individual and regional load types shall be dynamic, without requiring a rebuild/regenerate of the database.
vi.	Load curves shall be linked to conditional events such that if the event occurs, the load curve will be implemented for the associated loads. Each change to a load curve shall be associated with a start and end time.
vii.	The standard simulator shall provide load area events such that the area load profile is increased/decreased by a given MW amount when the event occurs (deterministic or conditional).
viii.	The instructor shall have the option to add an offset to the load curve upon the occurrence of the event. Provision shall be made to allow a multiplier to be applied to the entire load curve such that the same percentage increment is added to each load associated with the load curve.
ix.	It shall be possible to use deterministic and conditional events to effect the load model, emulating a cold front moving across the country and the reduced load restoration profile following a substation or regional blackout.

3.3.3.7 Instructor Intervention Relating to Generation Changes

Requirement Schedule:

i.	Facilities for rapid intervention relating to the changes to power station actions and events shall be provided.
ii.	The instructor shall be able to startup, shutdown, change the target generation, define the time to ramp up a generator and set the AGC state of any generator in the simulation via a single user interface.
iii.	When the instructor closes the breaker of the generator, the generator shall deliver, based on the generating unit type, the entered desired output: immediately and/or use the ramp rate to ramp the generator to the desired output.

3.3.3.8 Events

Requirement Schedule:

i.	Two (2) types of events shall be provided, i.e., time-based events and conditional events.
ii.	The introduction of spontaneous events in the power system shall be intuitive, such that when an event file is built, it shall be possible to insert the events using the drag and drop functionality from SCADA or network one-line displays.
iii.	Event insertion from one-line displays shall be provided using a single click and/or drag-and-drop function. Events shall be loaded quickly and easily, and appropriate logging shall be performed.
iv.	The instructor shall be able to activate and de-activate the audible alarm function from the instructor console.
v.	It shall be possible to extract unauthorised changes, for a user specified time interval, of all status indications, recorded in the historian. This data shall be used to create appropriate OTS events automatically.
vi.	It shall be possible to have an automated creation of scenarios with events-based input from the instructor during the training session that can be re-used in subsequent training sessions.

3.3.3.8.1 Time Based Events

Time-based events are specific desired network state changes, entered by the instructor into the simulator to take place based on a relative or fixed time. The instructor shall be able to:

- Copy, move, include or link the contents of existing event lists to the new event list;
- Set up a series of events that can be stored and recalled on demand allowing all operators to experience the same environment and conditions;
- Re-use saved event lists following database updates;
- Assign a specific timestamp to an event and move an event from one timestamp to another;
- Mark events and event lists as active or ignore on demand; and
- Insert new events into the current event list on the fly.

Requirement Schedule:

i.	At minimum, the instructor shall be able to manage time-based events as defined in 3.3.3.8.1.

3.3.3.8.2 Conditional Events

Conditional events are events that are loaded and remain active in the simulator during the simulation session. These shall behave as follows:

- When the condition occurs that triggers the event, the specified events list shall be activated;
- Conditional events shall provide ‘if-then-else’ logic supporting multiple threads and allow single-shot and multi-shot triggering;
- Boolean functions and/or values for comparison and branching to the corresponding events;
- Conditional events shall provide ‘case logic’ to trigger specific scenarios;
- Conditional events shall permit time-based selection such that the conditional event is only activated under specific time and/or a specific event condition; and
- Events in the event lists shall allow initiation based on relative times related to the initiating time not absolute time.

It shall be possible to create events on the following:

- All relay types;
- Programmable Logic Controllers (PLCs);
- Generators;
- Generation schedules;
- Load curves;
- Interchange scheduling;
- Control area modification;
- Circuit breakers and isolators;
- RTU failures;
- Station analogues and status indications;
- Overloading of Lines and Transformers;
- Six state auto-reclose (ARC) relays; and

- Station measurement noise and bias.
- Situational awareness – Effect of weather pattern factors

Requirement Schedule:

i.	The structure of conditional events shall conform to 3.3.3.8.2.
ii.	Events and/or actions shall be available on at least the equipment defined in 3.3.3.8.2.
iii.	Programmable logic shall be available to the instructor in the construction of a conditional event.

3.3.3.9 Initialisation

Requirement Schedule:

i.	The simulator shall initialise from a snapshot either from the real-time system or a defined state in the historian, including tags, notes, manual dressings and all other operator entered data. The snapshot shall contain all real-time system details including the loads, generation, AGC settings, dispatch rules, manual dressing of both modelled, non-modelled devices and contract data.
ii.	Initialisation with the frequency of 50 Hz, such as when the simulator is initialised from the historian, shall be provided. The actual power system frequency and busbar voltages at the time shall be used to initialise the starting conditions of a training session.
iii.	It shall be possible to initialise the simulator after execution of events from an event list. See 3.3.3.8.2.
iv.	At startup, the simulator shall be capable of importing all real-time data and displays from the real-time/production system into the simulator.
v.	Initialisation from a power flow shall not require more than one request and/or action from the instructor.
vi.	The preparation of the Operator Training Simulator shall include the definition and/or library of use cases for all the operator functions required for the balancing and maintenance of the reliability of the interconnected power system.

3.3.3.10 Operation

Requirement Schedule:

i.	The simulator shall mimic the operation of the real-time system as closely as possible. All supervisory control commands available on the online system shall be implemented on the simulator. Other functions associated with the real-time operation, such as manual dressing, tagging, etc. shall be simulated.
ii.	All Advanced Power Network applications from the EMS shall be available in the OTS.
iii.	The simulation shall include support for all operator functions and simulate interfaces with power stations operation including optimising the generation dispatch.
iv.	All operator control actions shall be implemented such that the power system dynamic response may be observed in the simulation.
v.	A clear distinction and separation of real-time power system operation and the operation of the simulator shall be provided. Operation of the simulator shall be at the same speed as the real-time system, faster or slower than the real-time system.

vi.	The internal relay models shall react such that the SCADA data shall be in line with the live system delivery rate.
vii.	Use of simulator from any workstation outside of the control room on the local network shall be possible.
viii.	The power flow simulation shall include all automatic controls available, such as auto tap changing control, generator reactive power limiting, etc, at a rate consistent with the power system.
ix.	Transmission line relaying due to faults, as well as reclosing, including 'trip, auto-reclose and trip' and 'trip and auto-reclose', shall be simulated. All relay data shall be activated or de-activated, on demand, from the instructor console, without the need to restart the simulator.
x.	In the event that the simulator 'crashes', or the power flow solution fails to solve, the instructor shall be able to restore the state of the simulation from the automatic backup just prior to the failure. The period between backups shall be user definable.
xi.	A message shall explain the reason why the simulator is going to 'crash' or fails to solve, for example: voltages are decreasing rapidly and a voltage collapse will start soon; not enough load on the system for the amount of generation on the system; and/or unable to solve because of too much MVAr on the system.
xii.	Storing and recovering sessions shall be available on full save cases containing all data; periodic/manual snapshots to rollback if needed; power flow snapshot, to rollback to previous converging power flow.

3.3.3.11 Outage and Workflow Management

Requirement Schedule:

i.	The simulator shall provide all functions associated with the Outage Management System (OMS). Provision shall be made to include workflow or job management exercises to include the linking of jobs to plant before, during and after hand-over.
ii.	The Outage Management System shall be supported by a detailed workflow order. In addition, the Outage Scheduler (OS) shall be delivered as standard on the simulator. It shall be possible to transfer the outage schedule from the online Energy Management System to the simulator to allow the trainee practising network studies based on actual planned outage information.

3.3.3.12 Logging/Messages

Requirement Schedule:

i.	The logs in the simulator shall include power system alarms and events, application runtime messages, simulator "crashing" or unable to solve messages as mentioned in 3.3.3.10 (x), simulator execution events and snapshot control information.
ii.	All events related to the simulator operation shall be logged as follows: all logs shall be easily accessible to the instructor on demand; log messages to refer to equipment by device name shall be operator friendly; and relay operation to include the reason for the trigger and the trigger value.

3.3.3.13 Source Code

Requirement Schedule:

i.	The source code for the simulator application software shall be identical to the online system, which is inclusive of Energy Management System, Generation Dispatch System, Situational Awareness functionality and the Wide Area Management System, thus fostering the use of a single version of the source code.
ii.	The management of the simulator application software and simulator control and/or simulation software shall be identical.
iii.	A test shall be performed on the regeneration of the entire simulator executable code from the single version of the source code used for the maintenance of the real-time system.
iv.	Any user defined logic for the real-time Wide Area Monitoring System shall also be available in the simulator.

3.3.4 Energy Management System

3.3.4.1 SCADA

3.3.4.1.1 Station Data Acquisition and Control

Requirement Schedule:

i.	IEC 60870-5-101 and / or IEC 60870-5-104 interoperability shall be implemented as described in detail in the *240-61478980 Eskom Slave device IEC 60870-5-101 Implementation Standard* and *240-61478967 Eskom Master device IEC 60870-5-101 Implementation Standard*.
ii.	All Application Protocol Data Units (APDU) as listed in the IEC 60870-5-101 specification shall be tested as part of both the factory and site acceptance testing.
iii.	The implementation of the protocol for the bitstring of 32-bit command shall meet the requirements as defined in the 240-61478967 Eskom Master device IEC 60870-5-101 Implementation Standard.
iv.	The Energy Management System (EMS) shall support data acquisition from Remote Terminal Equipment (RTEs). The Energy Management System (EMS) shall be able to monitor the state of the power system via telemetry from RTEs located in substations and power plants. Specifically, the EMS shall be capable of interfacing with RTEs that operate via IEC 60870-5-101 protocol and shall support the full suite of IEC 60870-5-101 messages including the bitstring of 32-bit command required for Automatic Generation Control (AGC). Baud rates of between 1200 bps and 19200 bps inclusive shall be supported.
v.	The capability to deactivate and reactivate the scanning of a given RTE upon operator command shall be provided as well as the capability of monitoring the availability of all RTEs from a central program. It shall be possible to force reporting on all data items on a selected remote source.
vi.	It shall be possible to manually activate or deactivate measurements on an individual or substation basis as well as reverse the sign. Reversing the sign of a measurement shall be available online by users with analyst or maintenance profiles.
vii.	It shall be possible to look at the loading profile of a device on the IPS using current and historical MW and MVAr SCADA flow data through that device or summation of loading of devices. For example: If transformer 1 of a substation is selected, it will be possible to see the current MW and MVAr loading, the MW and MVAr for the previous hour, the previous day etc. as available in the historian. Also, it shall be possible to do a summation of loading for more than one device selected. These outputs shall be available on a SCADA one-line display.

viii.	Each communication port on the front-end to the RTE shall be protocol-programmable and independent of each other, i.e., it shall be possible to run different protocols over each port. A communication line switching subsystem shall be supplied that allows communication lines to be switched either individually, or in groups between front-ends.
ix.	An alarm shall be generated when a bay processor or RTE fails. This facility shall not be triggered during system failover and / or switch-over.
x.	The system shall have a capability to multi-drop/multiplex at least eight (8) circuits per communication port or per line. Functionality shall be provided to switchover the circuit(s) from one front-end (main) to the other front-end (backup) from the workstation using a Graphical User Interface, without hard selecting the circuit(s) on the switchover equipment.
xi.	The system shall support a network address of two (2) bytes giving an address range of 0 to 65535 (decimal) and a datalink address of one (1) byte giving an address range of 0 to 255 (decimal). The network address shall be unique, but the datalink address can be reused as long as the link is unique.
xii.	It shall be possible to change the scan rate, jitter value, timeout, number of retries per circuit without requiring the reload / restart the front-end. The capability to configure each circuit either as an analogue or digital circuit shall be provided.
xiii.	It shall be possible to implement accurate time synchronisation of remote equipment from the TPSCM. GPS time stamping of all status indications and analogues shall be provided. The functionality shall exist to indicate the time source on all analogue and status indications from field, so that if an event is GPS time stamped, then the software applications can use this status. An accurate implementation shall be provided, of similar resolution to GPS, of synchronisation of remote equipment from the TPSCM. This shall require evaluation of how latencies are included and taken into consideration through all participants of the process such as substation automation network latencies and telecommunication latencies.
xiv.	It shall be possible for the real-time events replay application to change the order of alarms based on GPS time instead of how the alarms entered the TPSCM system. It shall be possible for applications to take latencies and non-deterministic characteristics from telecommunications systems and make appropriate allowances.
xv.	A function shall be provided to monitor, detect and log the time source of RTEs. Compare the sequence of event time with the data acquisition system's time to identify time issues at the substations.
xvi.	Data quality shall be reported up to all historian levels. Data quality for all SCADA data items shall be retained in all applications where the SCADA data item is used.
xvii.	Permanent oscillating status indication or analogue shall be suppressed and reactivated manually or configured for automated suppression and reactivation on the SCADA application level. No oscillating data item shall reduce the performance of the system under normal operating conditions, inclusive of the data acquisition server, as specified for normal conditions.
xviii.	The general interrogation rate shall be configurable to ensure proper reporting of all RTE data items.
xix.	All active communication ports shall be scanned simultaneously by the front-ends.
xx.	It shall be possible to store up to four (4) redundant telemetry values for a data item up to the historian level.
xxi.	It shall be possible to navigate to any of the multiple data sources, such as the historian, for a data item from the SCADA one-line display.

3.3.4.1.2 Inter Control Centre Data Exchange

Requirement Schedule:

i.	The operation of data links between the TPSCM and the Distribution Management Systems (DMS) at the Regional Control Centres, the Energy Management Systems of neighbouring foreign utilities and the Southern African Power Pool Co-ordination Centre(s) shall be modelled.
ii.	The redundant ICCP / IEC 60870-6-503 server at the PCC and SCC shall provide the transparency to link to any of the TPSCM servers to ensure reliable continuous operations.
iii.	The ICCP / IEC 60870-6-503 wide area network shall not be limited on the number of remote masters to be modelled. Multiple ICCP instances shall be deployed where limitations are experienced with a single ICCP installation. Each remote master configuration shall be capable of supporting dual redundant communication links.
iv.	The ICCP / IEC 60870-6-503 servers shall be located within a DMZ. Communication to each remote master shall be from a separate DMZ.
v.	The EMS shall be able to interface with remote masters that operate via the Inter-Control Centre Communications Protocol (ICCP / IEC 60870-6-503) and secure ICCP. Also, the ICCP application shall be compliant with TASE.2 version 2000-8 and be interoperable with systems using the older TASE.2 version 1996-8.
vi.	All conformance blocks shall be provided and specifically the following: Conformance Block 1 (Periodic Power System Data); Conformance Block 2 (Extended Data Set Condition Monitoring); Conformance Block 4 (Information Messages); and Conformance Block 5 (Device Control).
vii.	Data from lower voltage level lines and substations shall be sourced from the DMS systems to increase the robustness of the State Estimator by increasing the power system observability.
viii.	The data engineering and modelling tools available to maintain the ICCP database shall be consistent and integrated with the rest of the data item telemetry modelling.
ix.	The data quality of data items as represented on the Graphical User Interface shall be consistent regardless of the protocol used i.e. IEC 60870-5-101, IEC 60870-5-104 and ICCP / IEC 60870-6-503.

3.3.4.1.3 Enterprise Information Exchange

Requirement Schedule:

i.	An Open Database Connectivity (ODBC) driver shall make the data available from the real-time databases in the TPSCM.
ii.	The use of Webservices for information exchange to the Enterprise Information System shall be well documented for maintenance and support.
iii.	The link to the Enterprise Information System shall be through a firewall from a dedicated DMZ.

3.3.4.1.4 Time and Frequency Acquisition

Requirement Schedule:

i.	Time and frequency measurement equipment, GPS synchronised, shall be locally interfaced to the TPSCM system. The time error reference shall be user enterable on the time system. The frequency measurement systems shall comply with the standard *240-160474571 Measurement and recording of Eskom frequency* .

ii.	The time data shall be stored in the real-time database and available for normal display and use. The time information shall be used to periodically synchronise all equipment at both the PCC and SCC.
iii.	Time synchronisation for the production TPSCM shall require the following GPS units to be installed: five (5) at PCC, four (4) at SCC and single units at seven (7) remote locations. The remote units shall feed into PCC and SCC control rooms via separate dedicated telecommunication links and displayed separately on displays next to the rear projection system.
iv.	Separate frequency meters with displays and programmable alarms shall be provided at each desk at PCC, SCC, SOC, as well as at the PCC and SCC OTS.
v.	Automatic fail-over shall be provided if the primary time and frequency source becomes unavailable.
vi.	The frequency shall be stored in the real-time database and historian, as per one second measurements, and be available for normal display and used on all workstations and rear projection systems. Independent time and frequency, which are detached from the system, shall be displayed at all times in the PCC and SCC. The time and frequency equipment shall interface to new digital displays at PCC and SCC.
vii.	The GPS satellite time signal equipment, including an external antenna, cabling and a computer interface shall be provided.
viii.	The frequency of the local building electrical feed shall be monitored for deriving the frequency and time deviation values.
ix.	The displayed outputs shall include the system frequency (xx.xxx); GPS time (xx:xx:xx.xx); system time (xx:xx:xx.xx); and time deviation (x:xx)
x.	All computer nodes on the system shall be time synchronised to the GPS. This includes a) the time displayed on a display on the operator workstations but generated from a server; and b) the local operating system time on all the nodes.
xi.	All data captured in the SCADA and historian shall be GPS time stamped.

3.3.4.1.5 Data Quality

Requirement Schedule:

i.	Calculations shall be provided to do load balancing for each voltage level in a substation using Kirchoff's law. Functionality shall include triggering it manually or running it periodically.
ii.	A report on all balanced busbars and alarm out of balance busbars, using an error tolerance, shall be available.

3.3.4.2 Alarm Management

3.3.4.2.1 Alarm and Event Logging

Alarm management shall be configurable such that important alarm conditions may be reported in a clear, concise, and timely manner while the unimportant alarms, the majority, are recorded for later analysis and action. The objective is to ensure that the operator is not overwhelmed with so much data that it is difficult to recognise the existence of serious alarm conditions and to isolate the causes.

To this end, the following shall be met:

- An alarm hierarchy shall be configurable to annunciate more serious alarms in a more 'forceful' manner than less serious alarms;

- The age of the alarm shall be indicated by a suitable method;
- Redirection of the reporting of an alarm condition on selected devices associated with outages shall be possible, such that the alarms may be viewed by support staff but not interfere with normal control room operations;
- Limit violation alarming shall have dead-bands on return-to-normal alarms to prevent toggling of alarms;
- Alarms received shall be sustained for a user defined period before being alarmed to the operator;
- All detected changes shall be logged;
- Alarming based on calculated functions shall have all the features of a regular alarm data item;
- The most recent alarms shall be displayed in a global alarm summary with all alarms recorded for later analysis; and
- An alarm, with a clear identification description, shall be generated when the bay processor or RTE fails, this alarm shall be configurable to allow an audible tone to be raised.

The time and date of the alarm shall be kept with the alarm.

Inhibiting the reporting of a single alarm condition, or any part of the hierarchy the alarm belongs to, shall be available.

All analogue limit alarm data written to a log shall include the SCADA value preceding the limit values.

Alarms bins shall be provided as well as area of responsibility.

All data written to log files shall be stored, left justified and comma delimited, enabling the loading of these log files into spreadsheets.

The user interface for the alarm application shall display a full list of all inhibited/suppressed, manually overwritten and not-in-service alarms with the associated source of inhibition clearly identified, i.e., either local or remote. There shall be a display which identifies nuisance alarms.

A search function on alarm displays shall be available.

The difference between the normal operational states for equipment to its current state shall be detected and highlighted. For example, if the line is normally linked to busbar A, but the current linkage is to busbar B, an alert /alarm is required.

Alarms acknowledged at PCC shall be auto acknowledged at SCC, if so configured. Alarms that occur during, or directly after, a failover shall be distinguished from actual alarms that have occurred in response to events.

During alarm testing/ commissioning, the alarm shall be sent to the testing desk (ring fenced in terms of alarm bin and type allocation) and shall be prevented from going to operational users.

Where two or more areas are assigned to receive the same alarm, when one user acknowledges and deletes the alarm on the local alarm page, it shall not be deleted from the other user's alarm page until that user deletes it on their local alarm page. Where two or more users are assigned to operate in the same area, it shall be possible for only one user to receive the alarms for the area.

The re-alignment of alarms being presented to operators shall be based on GPS time field and not how the alarms entered the system. Any intelligent alarm processing shall include events whether they are GPS time stamped or not.

When a RTE is returned to service after an outage, alarms must be triggered if there is any changes from its previous scanned in state.

Requirement Schedule:

i.	The standard alarm processing shall include the functionality defined in 3.3.4.2.1.
ii.	Advanced and/or intelligent alarm processing shall be available through algorithms and/or chronicles defined prior to the acceptance testing.

iii.	Maintenance and support of the alarm databases and configurations shall be limited to the weekly database deployment cycle.
iv.	A single alarm interface shall be used for the TPSCM.

3.3.4.2.2 Area of responsibility:

Requirement Schedule:

i.	Area of responsibility shall be definable per user, per role, per function and per data item.
ii.	A central management tool shall be available to manage all the area of responsibilities in the TPSCM.
iii.	The definition of roles and associated area of responsibilities shall be consistent across all TPSCM functions.

3.3.4.2.3 Abnormal States

Requirement Schedule:

i.	All elements in an abnormal condition shall include a colour indicating the age of the abnormal element states. The initial abnormal age ranges shall allow for at least six (6) age ranges from minutes to over six (6) months.
ii.	List of data items in abnormal states shall be available through the power system hierarchy, such as electrical equipment, bay and substation.
iii.	It shall be possible to identify data items in an abnormal state on the one-line displays.

3.3.4.3 Reconstruction/ Replay

Requirement Schedule:

i.	Events that happened on the IPS shall be replayed on demand on a graphical user interface with the same ‘look and feel’ as the production system but with a clear indication that it is a reconstruction and / or replay occurring.
ii.	Criteria to trigger the storage of events on the IPS shall be user definable.
iii.	The functionality shall exist to use replay with alarm processing to investigate events.
iv.	It shall be possible to initialise a study using Advanced Power Network Applications during replay.
v.	The number of replay files to store on the online system shall be user definable.

3.3.4.4 Operator Entered Information

3.3.4.4.1 Tagging

The TPSCM system shall provide the capability of tagging a device, telemetered or non-telemetered, via a graphic display annotation. A device tag represents an operator action to draw visual attention to a device symbol on any station display indicating that supervisory control is either inhibited or cautioned for that device. Depending upon the type of tag, software shall inhibit supervisory control of the associated device. Each tag shall allow the operator to enter a comment that is easily accessible via the one-line displays and tabular displays. The functionality shall be provided to attach predefined comments to the newly created tag. The tag comment shall be visible on selection of the tag by the operator.

The ability to add and manipulate the additional sixteen (16) user definable flags, which will result in appropriate changes to graphical display of the flagged element, shall be available. Each flag shall have an appropriate editable note field displayable on demand.

It shall be possible to position a tag/flag at user definable locations in relation to the device or element on the display. Tags and flags shall be displayed using either graphical and/or text formats. Tags shall be retained during database updates.

Tags entered into the system at PCC shall be available at the SCC and all other control centre at all times. Operators shall be permitted to add tags to an object / data item without being presented with alarms associated with that object / data item. All users shall be able to read, add and remove all tags.

Requirement Schedule:

i.	The standard tagging shall at minimum include the functionality described in 3.3.4.4.1.
ii.	The area of responsibility for tagging and alarming shall be managed independently.

3.3.4.4.2 Notes

Requirement Schedule:

i.	The notes databases shall be synchronised across the sites and shall not require any re-synchronisation and / or merging of data when moving to / back from emergency operations or between the sites.
ii.	Synchronisation of the notes database after running the TPSCM split between the PCC and SCC shall present a first pass solution for selection or approval.
iii.	Notes shall be used for annotations to share information and reminders between operators. Annotations shall be associated with displays, alarms and any equipment and / or data item that can be uniquely identified.
iv.	It shall be possible to associate previously prepared files and / or information with a note.

3.3.4.4.3 Not-in-service

Requirement Schedule:

i.	It shall be possible to remove from service any data items, bay or substation via a dialogue box.
ii.	A telemetered data item defined as not-in-service shall enable the functionality for a manually entered replacement to be processed in the same way as telemetered indications.

iii.	All operator actions to remove a data item from service shall automatically uniquely identify the user and the workstation where the action was initiated from.

3.3.4.4.4 Test Mode

Requirement Schedule:

i.	It shall be possible to place a single data item, bays or complete stations and / or RTEs in a 'test mode' so that the associated events and / or alarms go into a separate summary from the real-time system alarms and / or events. The 'test mode' activation and deactivation shall be available during the offline data engineering and a real-time 'test mode' assignment dialogue box.

3.3.4.5 Data Processing

Requirement Schedule:

i.	The standard data processing shall include, for example, analogues, status indications, binary-coded decimal (BCD) indications, bit string, calculated data items, non-telemetered data items and user definable code units.
ii.	Data quality status for telemetered and calculated data shall clearly indicate the status of the data item.
iii.	Discrepancies between data from different data sources for a data item shall be highlighted.

3.3.4.5.1 Data Item Identification

Requirement Schedule:

i.	The identification of a data item shall include the full RTE address as well as the SCADA database identification tree.
ii.	The full identification of a data item shall be available on demand from any display through a dialogue box.

3.3.4.5.2 Analogues

After an analogue has been received without any communication errors, the following functions shall be performed:

- Data conversion to engineering units;
- Data calculation;
- Alarm limit checking;
- Data storage in the database; and
- Historical archiving.

The limit alarming shall include a user definable 'sustained' duration field value before the alarm is triggered.

Analogue processing shall include rate-of-change limit alarming. Frozen analogue detection shall include alarming.

Online modification to the raw-to-engineering conversion routine constants, without the need to restart the data acquisition systems, shall be provided. All data associated with the conversion routine shall be visible in the change window. The indication of the change shall be consistent in the mark-up of the data item up to the historian level. This action shall be executed by users with analyst or maintenance permissions at the data acquisition level, without a need for a full EMS database update.

Requirement Schedule:

i.	The data processing for analogues shall at minimum include the functionality described in 3.3.4.5.2.
ii.	A full description and operator manual on the standard data processing for analogues shall be provided.

3.3.4.5.3 Status Indications

Change-of-status, not initiated by the operator, shall result in ‘appropriate’ alarming and immediate display update. Operator initiated change-of-status shall not result in an alarm but shall result in immediate display update and logging of the state change as confirmation of the state change.

It shall be possible to link any status data to a visual indication of the device.

Requirement Schedule:

i.	The data processing for status indications shall at minimum include the functionality described in 3.3.4.5.3.
ii.	A full description and operator manual on the standard data processing for status indications shall be provided.
iii.	A library of graphical representation for status indications shall allow for inheritance of representation.

3.3.4.5.4 Binary Coded Decimal (BCD) indications

BCD indications shall be used to capture transformer tap positions. Tap data, due to the nature of the data source, shall be subjected to user definable buffering before limit alarming is performed. First and second derivative calculations for rate-of-change alarm processing shall be provided for all tap data.

Requirement Schedule:

i.	The data processing for status indications shall at minimum include the functionality described in 3.3.4.5.4.
ii.	A full description and operator manual on the standard data processing for BDC indications shall be provided.
iii.	Once converted a BCD indication shall have all the normal limit and / or alarm handling capabilities.

3.3.4.5.5 Bit String

Requirement Schedule:

i.	Bit string digital data is used to report the state of certain relays such as the six (6) state auto-reclose relays. The returned value shall be stored as an integer value in the SCADA database. The integer value shall be used as an index into a list of possible display texts.

ii.	It shall be possible to have a bit string digital data item with each bit corresponding to a status signal. The status signal for the bit shall be considered to be active as long as the bit is set and normal when the bit is reset.
iii.	A bit string digital data item shall be available for data processing, such as in calculations and displays.

3.3.4.5.6 Calculated Data Item

Requirement Schedule:

i.	The calculated data item function shall be used for calculations that shall be performed at a frequency close to the scan frequency; the frequency of calculations shall be user definable on an individual calculation basis.
ii.	The source and destination of the calculation shall be unrestricted.
iii.	It shall be possible to define a calculation as periodic or automatic when an input argument changes.
iv.	All data processing available for a telemetered data item, such as limit checking, alarming and logging, shall be applicable to a calculated data item.
v.	It shall be possible to add a calculated data item: i) during the off-line data engineering and modelling process; and ii) as part of the real-time process on the production system. The model for a calculated data item, created on the production system, shall be available for import into the master database.

3.3.4.5.7 Non-telemetered Data Items

Certain data in the database shall not be obtained via data acquisition. These data items shall include:

- Status indications;
- Analogues;

and shall be definable in the database similar to real-time (telemetered) data items.

The differentiation between telemetered and non-telemetered data items shall be transparent to accessing programs or applications. This data will be kept up to date by manual operator entry or, if so configured, by automatic estimation.

Event messages shall be logged to record any change.

Non-telemetered data item shall be shown on any display in the TPSCM. The non-telemetered data item shall be shown on the displays and recorded in the reports in a manner, which will differentiate them from the operator entered replacements for deactivated real-time data item.

This non-telemetered data item shall not be lost under any condition including database updates / modifications and there shall be an audit trail back to the point of origin.

Requirement Schedule:

i.	The data processing for non-telemetered data items shall at minimum include the functionality described in 3.3.4.5.7.
ii.	It shall be possible to associate power system controls with a non-telemetered data item.

3.3.4.5.8 User Definable Code Units

Requirement Schedule:

i.	It shall be possible to trigger a user definable code module following a state change, analogue limit infringement or a first or second derivative limit infringement.
ii.	The generation of an alarm message on any state change or limit infringement due to the execution of user definable code shall be configurable.

3.3.4.6 Advanced Power Network Applications

3.3.4.6.1 Advanced Power Equipment Models

Models for all equipment in use on the IPS shall be provided. The models shall be applicable to all advanced power network applications. Provision shall be made to handle the full dynamic range and internal behaviour as experienced by the operator in the operation of the primary and secondary equipment.

Modelling tools to enable the formulation of user definable models shall be provided.

The following functionality for the SVC shall be provided for all advanced network applications:

- The SVC shall be modelled correctly to reflect the SVC in the *Employer's* power system: the model shall include saturation behaviour at both leading and lagging limits;
- SVC remote breaker switching;
- SVC operational mode changing from constant reactive power, Q, output to constant voltage setpoint.

Modelling of inter-tripping schemes shall be provided by adding post-processing routines to the Power Flow Analysis. Post-processing shall be automatically activated at the end of a power flow solution and shall list, in a dedicated display, the equipment that would trip, if any. A general routine for defining inter-tripping schemes shall be provided. The action of interruptible loads shall be modelled via inter-tripping schemes.

Modelling for under-frequency load shedding shall be provided.

Ability to add logic to all models to simulate steady state behaviour shall be provided. Examples would be 1) the inter-tripping of lines during power flow studies when circuits are overloaded; and 2) the action of interruptible loads.

Generation rescheduling, in the advanced network application, shall include manually changing the unit sentout data or changing the unit participation factors. The power flow studies shall facilitate look-ahead studies by taking into account:

- Generation schedules determined by the Generation Dispatch System; and
- Planned maintenance (outages).

All schedules and outages shall be available for the advanced network applications.

Reliable and detailed generator models shall be provided for steam, hydro, pump storage, gas turbines, nuclear and renewable models such as photovoltaic, wind, concentrated solar power and battery storage, including electric vehicles and models to represent customer power injection to the grid etc. These models should be reflective of the real-time environment and should also be adjustable to cater for DIgSILENT/PSS®E users where more detail is required. It shall be possible to change modelling parameters for the generator models to meet existing and new operating requirements.

Equivalencing for power system equipment shall correctly map the characteristics in terms of the behaviour and impact on the interconnected power system. The advanced network applications and models shall be available in real-time, study and look-ahead mode.

A period of at least 1 (one) month specialist support shall be required to work with the *Employer*, to implement the models during model conversion from the current EMS to the new EMS.

Requirement Schedule:

i.	The standard TPSCM solution shall include the functionality defined in 3.3.4.6.1 for the advanced power network models.
ii.	The advanced power network models shall consider distributed energy resources.

3.3.4.6.2 Power System Model Adaptation

The Power System Model Adaptation function shall be used to maintain schedule information for database-defined day types, time of day and month of the year. Together with scheduling information provided by other sources, model adaptation data shall be used by other security analysis functions to obtain time dependent values for:

- Breaker positions;
- Loads; and
- Scheduled voltage setpoints.

The Power System Model Adaptation shall provide for the load curves. Model adaptation shall provide the following capabilities:

- The number of day types shall be configurable. As a minimum, seven (7) day types shall be available for the days of the week, and another fourteen (14) day types for example the public holidays.
- Time of the day shall be determined by specifying time intervals over a twenty (24) hour period. These time intervals shall be of varying length, to be defined via database input. Time intervals shall allow a granularity of one (1) hour.

These load patterns shall contain for each load, the real and reactive power values. For the definition of the loads at the different nodes, a load pattern shall be used.

It shall be possible to specify different patterns for seasons, public holidays, weekday and time of the day. The load pattern shall be grouped according to the following requirements:

- Four seasons (spring, summer, autumn, winter);
- Six types of days (Monday, working day, Friday, Saturday, Sunday, holiday);
- Four (4) time domains (peak load in the morning, normal load during the day, peak load in the evening, minimum load during the night); and
- Cold front simulation passing across the country.

Therefore, ninety-six (96) load patterns shall be stored.

Standardisation of the load values within one (1) load pattern yields a set of distribution factors. The forecasted total active load shall be distributed on the individual loads with the help of the distribution factors. The reactive power of the individual loads shall be determined with the help of the cos θ values, defined in the respective load pattern.

Requirement Schedule:

i.	The standard TPSCM solution shall include the functionality defined in 3.3.4.6.2 for the Power Model System Adaptation.

3.3.4.6.3 Available Transmission Capacity

Requirement Schedule:

i.	Branch groups and/or transfer interface shall be defined for a grouping of transmission lines and/or tie-lines connecting one area to another. Branch group totals shall be calculated and shall be displayed in tabular displays, one-line displays and graphs.
ii.	The Available Transfer Capacity (ATC) shall be calculated in real-time, study or day-ahead and/or intra-day congestion forecast mode.
iii.	The monitoring of the spare capacity available to increase the energy transfer into that area shall be based on thermal and voltage stability limits available in network analysis tools.

3.3.4.6.4 Power System network model

The State Estimator shall solve observable parts (or internal model) and unobservable parts (or external model) of the IPS. The State Estimator shall combine estimated and non-estimated parts of the IPS to form a complete network model.

The State Estimator shall use a robust and reliable algorithm to simultaneously solve the observable and non-observable parts of a network. An observability algorithm shall complete the observability, by including pseudo-measurements with low weights, where needed.

No specific processing for non-estimated parts shall be required since all parts of the modelled network shall be included in the estimation.

Boundary measurements (i.e. measurements on tie-lines to neighbouring networks), with very good accuracy, shall be handled through the State Estimator accuracy classes assigned to all telemetered data.

The power flow condition of the IPS shall be determined with an algorithm, which is numerically robust and makes use of all types of available information, including equality conditions at the boundary nodes of the estimated part of the IPS.

The weighting factors of the pseudo measurements shall be determined in such a way, that the 'mismatches' between SCADA measurements and estimates at the boundary nodes shall be minimised.

The external model shall be considered quite adequate when subsequent analysis done on the internal model accurately reflects the effects of the external model. This analysis may be any of the advanced network studies, such as contingency analysis, power flow analysis, security constrained dispatch or optimal power flow.

When the internal and external models are being solved, care shall be taken that external errors do not distort internal results. It shall be possible to model data from sub-transmission networks from information received from other control centres. For example, the State Estimator shall be able to provide estimates for sub-transmission networks using data from the Distribution Management Systems (DMSs); renewable plant including Battery Energy Storage (BES) and Independent Power Producers (IPP’s) providing generation data via different data protocols.

Requirement Schedule:

i.	The standard TPSCM solution shall include the functionality defined in 3.3.4.6.4 for the power system network model.

3.3.4.6.5 Plausibility Check of Measurements

The plausibility of the SCADA measurements shall be checked before these values are used in state estimation, for example:

- Comparison of voltage measurements at a node;

- Kirchhoff's law for real power, P, and reactive power, Q, measurements at a node;
- Comparison of the branch flows with the position of the corresponding switches; and
- Comparison of the measurements on both sides of a line, e.g., quantity and flow direction of each measurement.

The following standard plausibility checks for the State Estimator shall be provided:

- Branches that have defined flow limits, measurements shall be tested against a multiple of the largest limit. If the measurement is greater, it shall not be used.
- If a generator’s MW or MVAr measurement has failed or is suspect in SCADA, the measurement shall automatically be skipped and not be used.
- If a generator's MW or MVAr measurement is greater than its MVA rating, the measurement shall not be used.
- If a load's MW or MVAr measurement is outside the specified limits the measurement shall not be used.
- Non-zero flow measurements on open branches shall not be used.
- Unreasonable flow measurements of non-synchronised generators shall not be used.
- Voltage measurements that deviate by more than a predefined percentage (%) of nominal kV shall not be used.
- In addition, it shall be possible to define SCADA calculations to raise an alarm if the measured flow difference from the two ends of a line exceeds a threshold.
- Implausible measurements shall be eliminated and not be used within the State Estimator.
- In the event that the breaker positions of some transmission lines are not telemetered, but flow measurement telemetry (P and/or Q) is available, standard functions shall set the appropriate breaker state to open/closed as a function of the telemetered P and/or Q values. The list of modified states shall be reported and displayed to the operator.

The presence of any implausibility shall be logged and indicated on displays. Descriptive information about the implausibility shall be provided. Where possible, this information shall include the data value that is most likely to be erroneous.

Implausible measurements, detected by plausibility check shall be marked on the one-line displays, for instance by changing their colour. Implausible SCADA values shall be replaced on demand by the State Estimator value.

It shall be possible to modify modelling parameters for power equipment (R, X and B impedance, associate length values, nominal values etc.) online. Access shall be via a pop-up window after selecting the object, i.e. line, transformer, load, shunt device etc. The modification routine shall include the normal plausibility checking.

Requirement Schedule:

i.	The standard TPSCM solution shall include the functionality defined in 3.3.4.6.5 for the plausibility checks on the measurements.

3.3.4.6.6 Topology Determination

The actual switching condition of the IPS shall be determined based on the fixed connections and flows between the different elements of the IPS and the actual status of the circuit breakers and isolators.

The determination of the topology shall detect an inconsistent switch status. The detection of incorrect switch positions shall consider all telemetered measurements and switch indications as well as manually entered values. It shall be possible to select this function to be either enabled or disabled. The results of the switch positions shall be treated in the same way as bad data.

The topology processor shall select the status of circuit breakers and switches from the real-time data and, using the connectivity data from the network database, determine the present IPS topology. This model shall be used as a base for all further calculations.

The State Estimator shall use the network topology, as defined by the Topology Determination, and all the other SCADA measurements to solve for the state variables.

The network topology processor shall determine the new network topology whenever there is a change in the status indication for a circuit breaker or link. Status indications can be telemetered or non-telemetered.

The operator can manually change the state of the IPS switches.

The output of the network topology processor shall be the data that describe a bus-branch oriented network. Thus, each of the buses shall be identified together with the generation, loads and shunts at these buses. Also the connectivity between the buses, due to the transmission lines and transformers, shall be described.

The network topology processor shall identify network islands and discard those that are not energised, i.e. have no generation. It shall be possible for the operator to check the switching condition of the model and the formation of islands with the help of one-line displays.

The network topology processor shall be used in both real-time and study modes.

Authorised users shall be able to:

- monitor network connectivity, network islanding, statuses of switching devices / equipment; and
- review an abnormal switching device status for manual status override.

One-line and tabular displays shall be provided for the review of telemetered, manually entered and non-telemetered data items.

Topology Determination shall also provide the following information:

- Summary of split buses, open-ended branches and de-energised equipment; and
- List of equipment in each network island.

Graphical presentation of islands, split buses, open-ended branches and de-energised equipment shall be available on overview displays and one-line displays.

Requirement Schedule:

i.	The standard TPSCM solution shall include the functionality defined in 3.3.4.6.6 for a topology coherency check and real-time topology estimation.

3.3.4.6.7 State Estimator

The State Estimator shall provide a complete and consistent set of measurements, i.e. a set of measurements that fulfils the power flow equations. State estimation shall be executed:

- Cyclically, that is not more than two (2) seconds, at a user defined interval close to the real-time scan rate;
- Event driven after a change of the node branch-model of the power system;
- On operator request; and
- In a real-time mode and in a study / offline mode.

SCADA shall supply the State Estimator with status indications, for the circuit breakers and links, and analogues of at least the following quantities:

- Network component real and reactive power flows;
- Bus voltage magnitude values;

- Transformer and phase shifter tap positions;
- Transformer current magnitude measurements;
- Magnitude of current flows along transmission lines; and
- PMU (Phasor Measurement Unit) measurements such as voltages, angles, real and reactive power.

Modelled data or pseudo-measurements shall also be used as input data to the State Estimator for network portions where SCADA measurements are unavailable or not sufficient. Pseudo-measurements of at least the following quantities shall be used:

- Generator real and reactive power injections;
- Load real and reactive power injections; and
- Bus power equality constraints, i.e., the sums of real and reactive power at each bus shall equal zero, respectively.

A comparison between all the SCADA measurements, including tap positions, and the estimated state variables shall be provided indicating any excessive differences between telemetered and estimated values.

The State Estimator shall be capable of handling bus sectionalising, as well as multiple measurements of the same electrical quantity. For example, multiple voltage measurement data inputs at buses that are capable of sectionalisation shall be allowed.

The State Estimator shall also be capable to solve for a system consisting of multiple islands.

The State Estimator shall detect and identify both single and multiple bad data using statistical techniques. When a measurement is detected as bad, a quality flag / data attribute shall be set for the given measurement in the database resulting in a unique presentation on displays. The history of a bad measurement shall be kept.

The manual activation or deactivation of measurements on an individual or substation basis, reversing of the sign and assigning weighting factors to measurement values or class of measurement values shall be provided.

Topology Determination shall be available as part of state estimation.

The State Estimator shall be able to provide the user feedback on the reliability of the results such as the cost function and degrees of freedom.

Bus power equality constraints shall have limit alarming processing for both SCADA and State Estimator.

It shall be possible to have manually entered measurements, SCADA measurement calculations and/or calculation references for use as input to the State Estimator. These manually entered measurements shall also act as real SCADA measurements and shall be of the same type as available SCADA measurements, e.g., P and Q measurements for transformers and lines.

The State Estimator shall perform estimation for the following:

- Tap positions of transformers and phase shifters;
- Conforming loads;
- Circuit breaker schedules; and
- Voltage regulation schedules.

To obtain reliable pseudo-measurements for use in estimating that portion of the network, which is not measurement-observable, the State Estimator shall adjust modelled data to model the effects of at least the following controls:

- Interchange control for regulating the flow of power between operating areas;
- Automatic generation control for adjusting estimated real power output in order to meet generation and interchange requirements;

- Automatic watt regulation for adjusting estimated phase shifter tap positions to regulate the flow between buses; and
- Automatic voltage regulation for adjusting generators' reactive power outputs and transformer taps to regulate bus voltages.

There shall be an indication of the process state of the State Estimator of at least the following types:

- Active and currently running;
- Active but not currently running; and
- Not active or down.

The State Estimator shall use alarms for notifications to operators. Reports shall be available on module execution activities, data quality statistics and error messages.

There shall be an indication of the measurement accuracy class models used, e.g., percentage values for:

- Potential transformer maximum error for full scale reading;
- Current transformer maximum error for full scale reading;
- Transducer maximum error for full scale reading; and
- Analogue to digital converter maximum error.

Load type model parameters shall be configurable.

All State Estimator outputs shall be available on the one-line displays, schematic overviews and/or tabular displays.

Requirement Schedule:

i.	The standard TPSCM solution shall include the functionality defined in 3.3.4.6.7 for the State Estimator.

3.3.4.6.8 Network Studies

The State Estimator shall be available as a study tool, interacting directly with the estimation process via executable functions and user definable parameters.

All network studies shall be available on the operator workstations in the control centres and in the DMZ for engineering users on the corporate network. A study in the DMZ shall be initialised from a replicated real-time database or saved study cases.

A separate environment shall be provided for study purposes only, with the time and date of the last study estimator execution displayed.

It shall be possible to manually run the estimation process multiple times on a given set of measurements. This can be useful to detect and analyse model errors.

From the available list of all SCADA measurements which are used as input data, it shall be possible to manually change these SCADA measurements prior to a state estimation. By default, the State Estimator shall retrieve the latest SCADA data, e.g., status indications and analogues, prior to an estimation.

The study State Estimator shall be initialised from modelling databases, a previous study solution, a previous online state estimator solution and a previous online power flow solution. Several initial conditions shall be available to select from, e.g., flat start.

Functions such as topology processing and observability determination, shall be individually executed along with descriptive messages explaining the results obtained for each function. It shall be possible to determine the critical measurements available from the results obtained via the observability processor.

Changing of statistical parameters shall be available prior to an estimation.

It shall be possible to modify modelling parameters for power equipment (R, X and B impedance, associate length values, nominal values, series impedances etc.), both in the online and network study environment.

Requirement Schedule:

i.	The standard TPSCM solution shall include the functionality defined in 3.3.4.6.8 for network studies.
ii.	All real-time network tools shall have an equivalent study version.

3.3.4.6.9 Study Base Case Initialisation

Study Base Case Initialisation shall be used to create a base case for a power flow study. It shall be possible to initialise a study base case using information available from:

- The most recent State Estimator solution;
- Stored Power Flow Analysis solution;
- Stored State Estimator solution;
- External flat files obtained from the outage scheduler, load forecast, unit commitment, and area interchange;
- Modelled default or normal values; and
- Latest dispatch schedules.

By specifying a date and time in the future, the base case for a given date and time shall automatically be constructed using data from the latest dispatch schedules, scheduled equipment outages, and the Power System Model Adaptation. If a State Estimator save case is retrieved, it shall be possible to scale the load-based on the load distribution in that particular save case.

Multiple users with multiple independent working areas shall be supported. Each user shall have an individual working area, which shall be used as a temporary location to gather information needed to run a study, modify the data as needed to represent the desired study conditions, and temporarily hold the study results. The users shall reside both on the corporate network and on the operational network in the control centres.

It shall be possible to remove tags, inhibits, etc. from all equipment upon initialisation. However, generator information, such as AGC status, limits, etc., shall be consistent with the source application.

Requirement Schedule:

i.	The standard TPSCM solution shall include the functionality defined in 3.3.4.6.9 for the Study Base Case Initialisation.

3.3.4.6.10 Power Flow Analysis

The Power Flow Analysis (PFA) shall have the generator reactive power limits at various real powers modelled to reflect the IPS.

The saturation for SVCs in both the leading and lagging regions, as a reactor or capacitor, shall be modelled for the IPS. The ability to update real-time parameters, e.g., voltage setpoint shall be included.

It shall be possible to define additional user models to represent the IPS, e.g., shunts with applicable switching logic, power dispatch of generators by AGC and governors, voltage control of the IPS, standard and phase shifting transformers with any associated control logic and the ability to lock taps.

The PFA shall include models for unique Flexible AC transmission system (FACTS) devices in the IPS including:

- Static VAr Compensators with local and remote controlled reactor and capacitor banks;
- Pump / storage hydro schemes with pumping, generating and synchronised condenser operation modes;
- Master follower transformers;
- Series capacitors;
- Shunt reactors and capacitors; and
- DC lines with both single and double poles being active.

FACTS devices are used to:

- Balance the load in unbalanced parallel lines by dynamically distributing the load over all three phases and across parallel lines; and
- Control the voltage on one or more busbars by controlling the generation or absorption of reactive power at target busbars.

Some of the FACTS devices have the capacity to control the switching of external shunt reactive power devices. The PFA shall mimic the automatic switching of these local and remote reactors and capacitors as the voltage at the monitored busbars change.

Multiple island network conditions shall be allowed.

Initialisation of the PFA can be from real-time. The operator shall have the ability to:

- Enter data and modify a snapshot of real-time data;
- Change equipment limits;
- Define limits for all pieces of equipment and for any area of the network; and
- Adjust the power flow parameters from the operator workstations.

All results shall be visible and consistent in the GUI. The operator shall have the ability to drill down or drill up on the information displayed as part of the standard outputs. The default output for the power flows shall be on the one-line displays. The output detailing information on the iteration process shall include, e.g., the largest mismatch, and busbar at which it occurs, to assist in finding problem areas in the network.

The power flow shall interact with all other power system analysis tools. Third (3rd) party engines shall be integrated by exporting State Estimator results in one of the supported formats (PSS®E and IEEE).

The power flow as described above shall be available simultaneously inside and outside the control room in real-time and study mode. It shall be possible to have at least twenty (20) independent PFA studies running in parallel. Four (4) of the studies shall be allocated to workstations in control centres and the others shall be accessible from the corporate network.

Requirement Schedule:

i.	The standard TPSCM solution shall include the functionality defined in 3.3.4.6.10 for the Power Flow Analysis.

3.3.4.6.11 Contingency Analysis

The input to the Contingency Analysis shall be initialised from real-time, or from any power flow scenario, i.e. historical or projected.

To reduce the execution time for the analysis, a screening tool shall be provided which can quickly simulate all contingencies and associate a relative risk index to each contingency. The worst contingencies (number to be user definable) shall be studied in detail and the results provided.

A description shall be provided of which criteria are used in the ranking algorithm, and how they are weighted.

Contingency Analysis shall include both real-time and study versions of the application.

As a minimum, the Contingency Analysis shall be able to process the following contingency types for a single and multiple island base cases:

- Single branch;
- Multiple branches;
- Bus-section;
- Generator;
- Synchronous condenser;
- Static VAr Compensator;
- Shunt elements;
- Loads; and
- Any combination of the above.

The contingencies shall be able to cater for energising and the de-energising of equipment including islanding.

The Contingency Analysis shall run periodically at a user defined time interval and it shall be event triggered, where the event shall be user definable, and it shall be manually triggered at any time.

An automatic list of contingencies shall be generated. These may include single or multiple contingencies, as indicated by the user.

Constraints, which constitute the limits shall be specified, e.g., 100% normal rating of lines or 0.95 per unit under-voltage.

The user shall be able to add contingencies to the screening tool, as well as specify contingencies that shall be studied in detail, regardless of where they are ranked according to the risk index. It shall also be possible to exclude certain contingencies from the list of contingencies to be studied, e.g., known radial feeds.

Bypassing of series capacitors shall always be part of the contingencies to be studied.

Simulation of inter-tripping schemes, e.g., where a line trip result in load and/or reactive power devices being tripped shall be included in the analysis. For these schemes, Contingency Analysis shall simulate the trip of the primary component(s), evaluate the supervised element against its limits and, if these limits are violated, simulate the trip of the conditional component(s).

Conditional contingencies, e.g., where one-line trips resulting in the overload and tripping of another line, shall be modelled. The inclusion of protection functionality and logic shall be available. A conditional contingency shall be composed of one or more primary components, a supervised element (bus voltage, line/transformer overflow etc.) or one or more conditional components. Conditional contingency capabilities to support more than one supervised element shall be provided. Protection functionality and logic shall be available through conditional contingencies. Explicit simulation of protection operations as well as cascading events shall be done in the Operator Training Simulator.

As meaningful output format is essential, the user shall have the functionality to select the variables to be viewed. These outputs shall be available for enhanced situational awareness. The following shall be clearly highlighted:

- Equipment overloads;
- Voltages that are out of limits, i.e., high or low;
- The number of violations, i.e., voltage and overloads;
- Formation of islands;
- Any contingency whose “risk ranking” has increased to a user defined value;
- Harmless contingencies as a result from the screening tool; and

- In the case of potential voltage collapse / non-convergence, the data shall be transferred to the Voltage Security Assessment for further analysis.

It shall be possible to select from the list of contingencies, by a single mouse click, any one of those cases studied in detail and be able to view the results in detail.

The output from every Contingency Analysis run shall be able to be stored for future reference and shall be exportable to other packages as well as being able to be used in the building up of scenarios. Severe problems that are identified based on the real-time network operating point shall be brought to the attention of the operator immediately and highlighted as a problem. This is of particular importance when considering the periodic execution as well as those executions based on equipment status change.

Violations detected shall be made known to the operators via graphical means, enhanced situational awareness and where applicable via the alarm system. Advanced graphical facilities shall allow the operator to quickly and easily identify problem areas in the network, via the one-line displays and situational awareness interface on the operator workstations and the rear projection system.

The operators shall be able to quickly and easily add and remove groups of contingencies on demand. The functionality shall exist for new contingencies to be added and existing ones to be modified or deleted by operators as and when required. It shall be possible to make each contingency conditional depending upon user needs and not limited to the contingency group. It shall be possible to mark selected contingencies as “must run” irrespective of the primary trigger conditions. Events to be studied shall include environmental and weather factors such as 1) a snowstorm that is coming towards the Cape and which may cause lines in Cape area to trip; or 2) a fire that started under a Transmission line that will cause the line to trip.

Contingency groups shall be used mainly as a practical means of activating/deactivating large sets of contingencies. Groups of contingencies can be activated or deactivated from the GUI, based on multiple network conditions and shall not be limited to a single trigger value.

It shall be possible to automatically populate the contingency data for single equipment loss contingencies and import a list of contingencies from external tools. The definitions of the contingencies shall be stored in the master database. All operator modified configurations and parameters shall be transferred back to the master database as master copy of all IPS operating and control data. An audit report of the changes shall be maintained.

The output from the Contingency Analysis shall be accessible by the Power Flow Analysis for study purposes.

Requirement Schedule:

i.	The standard TPSCM solution shall include the functionality defined in 3.3.4.6.11 for the Contingency Analysis.

3.3.4.6.12 Short Circuit Analysis

Short Circuit Analysis (SCA) shall provide the operator with an accurate indication of what is happening on the system during any possible contingency, in terms of fault levels.

Short Circuit Analysis shall interface with power flow model requirements for specific system plant such as Static VAr Compensators. In order to provide the required accuracy, the positive, negative, and zero sequence components for all system plant shall be available for the IPS.

It shall be possible to import, in database defined formats, additional equipment information required to provide the correct fault levels at all transmission voltages.

SCA shall be initialised from real-time, or from any power flow scenario, i.e., historical, projected or contingency. It shall be possible to store and/or save all contingencies and fault incident models.

As a minimum, both real-time and study versions shall be included.

Short Circuit Analysis shall run periodically at user defined intervals.

As a minimum Short Circuit Analysis shall be able to process the following types of balanced and unbalanced faults for multiple island base cases:

- Single phase;
- Phase-phase and double-phase-ground;
- Open-phase
- Three-phase; and
- DC line faults.

Where the event is user defined, the fault or fault combination shall be simulated at will.

The output format shall be user definable/selectable in terms of all variables and busbar names. It shall be possible to retrieve any stored analysis, through a single mouse click, and be able to view the results of the fault studies done in detail.

It shall be possible to print and export the results to other packages such as spreadsheet and external relational databases. A detailed graphical representation of any portion of the modelled system around the faulted area inclusive of results shall be available.

Result variables shall be user selectable. Output of the total sequence data set for any fault to a default or user defined file in a format suitable to other packages shall be available. Initial data transfer scripts that can be modified later on by the user shall be provided.

SCA shall therefore be able to solve the network and any prevailing unbalance condition. It shall also be possible to manually enable or disable any plant prior to doing a user defined study.

Initial conditions for SCA are always a balanced network (from a power flow or state estimator solution). From this initial state it shall be possible to simulate balanced and unbalanced faults.

The SCA program shall be able to determine the fault levels at all busbars in the network and be able to present this data to the operators graphically. The graphics shall allow the operators to quickly and easily identify problem areas in the network, via both the GUI and the rear projection system displays.

The operators shall be able to quickly and easily add and remove fault groups on demand via one-line displays. It shall be possible for new faults to be added and existing ones to be modified or deleted by the operators as and when required.

Fault groups shall be easily activated or deactivated from the user interface. In addition, an option shall be provided to simultaneously analyse the outage of each of the devices connected to a faulted node.

It shall be possible to mark selected faults as ‘must run’ irrespective of the primary trigger conditions.

The user shall be able to identify the stations at which results are to be shown. The format, i.e. per unit or actual, of the results are to be user definable.

To effectively use the tool to indicate fault level changes, it is necessary to track the changes over time for pre-fault, fault and post fault conditions. Fault level variations at different busbars shall be monitored and the operator notified when a specific user definable threshold is exceeded.

All operator modified configurations and parameters shall be transferred back to the database modelling tool as master copy of all power system operating and control data.

Requirement Schedule:

i.	The standard TPSCM solution shall include the functionality defined in 3.3.4.6.12 for the Short Circuit Analysis.

3.3.4.6.13 Optimal Power Flow

The Optimal Power Flow shall be capable of optimising both for reactive and real power flows. The Optimal Power Flow shall be available as part of the study and real-time advanced network applications.

The optimisation shall include:

- Reactive power optimisation through the following objective function:
  a) Minimisation of the total or partial loss of the IPS;
  b) Maximisation of the reactive power reserve; and
  c) Interior-point method optimisation of the reactive power;

  By using controls such as:
  - Generator reactive power;
  - Transformer and shunt taps; and
  - Static VAr Compensators;

  With flexible constraints:
  - Branch flow and voltage limits;
  - Generator reactive power limits;
  - Reactive power reserve; and
  - Boundary flows.
- Economic and/or optimised generation dispatch through the following objective functions:
  a) Minimisation of losses;
  b) Minimisation of costs obtained from the Generation Dispatch System;
  c) Minimisation of load shedding;
  d) Interior-point method for AC optimisation; and
  e) Linear programming for DC optimisation;

  By using controls such as:
  - Generator real and reactive power;
  - Transformer and shunt taps; and
  - Static VAr Compensators;

  With flexible constraints:
  - Branch flow and voltage limits;
  - Generator real and reactive power limits;
  - Real and reactive power reserves;
  - Boundary flows; and
  - DC only contingency constraints.

Requirement Schedule:

i.	The standard TPSCM solution shall include the functionality defined in 3.3.4.6.13 for the Optimal Power Flow.
ii.	The results from the Optimal Power Flow shall not contradict the results of the Generation Dispatch System in the TPSCM.
iii.	Security constrained limits shall be consistently applied in the Optimal Power Flow and Generation Dispatch System.

3.3.4.6.14 Dynamic Security Assessment

Dynamic Security Assessment (DSA) of the power system shall be provided by the following:

- Transient Security Assessment (TSA) function in study mode;
- Voltage Security Assessment (VSA) function in real-time and study mode; and
- Small Signal Analysis Tool in real-time and study mode.

The Voltage Security shall be automatically activated as part of the online network processing sequence and shall use the latest network state produced by the State Estimator or any other advanced network application.

In addition, both VSAT and TSAT shall be integrated in the study network processing sequence and shall be executed under operator request from a power flow initial state.

Analysis can be triggered due to events from the IPS, manual activation, pre-defined time-based schedules and any change in load.

DSA shall periodically do time-domain analysis of user defined rule-based contingencies and those contingencies identified as critical by the fast-screening tool. DSA shall provide a fast-screening tool for network contingencies up to n-1.

DSA shall perform security assessment, determine and provide transient security limits whenever IPS changes occur and whenever the load is increased by a user specified amount. Apart from default safety margins, user defined safety margins shall be permitted. When not specified by the user, transient security limits shall be based on default safety margins.

DSA algorithms shall allow for fixed and variable step-size integration.

DSA shall recommend remedial actions. The ranking of contingency algorithms by the DSA shall be provided and explained. The user shall be able to specify multiple contingencies. Customisable post processing ability including default variables and user defined rules shall be provided. All input data, algorithm parameters and analysis output shall be available in graphical, tabular and database format for processing by staff.

DSA shall allow modelling in time and Laplace domain of generators, FACTS, SVC, HVDC and other user specified power devices. The graphical modelling interface shall facilitate the combination of models by the user.

Results shall be visible on all operator workstations in the control room. Results shall be displayed on the Situational Awareness, for a global view of the risks detected, like transfer limits allowed between regions before having stability issues. The results from offline studies shall be available from any engineering workstation.

Requirement Schedule:

i.	The standard TPSCM solution shall include the functionality defined in 3.3.4.6.14 for the Dynamic Security Assessment.

3.3.4.6.15 Look Ahead

Requirement Schedule:

i.	A power system look ahead function, providing a power flow and contingency analysis for multiple time points, shall be available for operators to evaluate outages and dispatch schedules.

3.3.4.6.16 Online Inertia

A tool shall be provided for online prediction of system inertia, rate of change of frequency and frequency nadir following a disturbance.

It shall be possible to verify the accuracy of the calculations and/or formulas and the impact of loss of load on the calculated system inertia. The calculation of the system inertia shall assist forward planning based on scheduling of units and planned outages and also the contribution from the neighbouring countries based on the bids. It shall be possible to include the system inertia in the audit trail on decisions to curtail renewable generation rather putting units in cold reserve and/or two shifting based on the level of required inertia and primary response from the cheaper coal units.

Requirement Schedule:

i.	The standard TPSCM solution shall include the functionality defined in 3.3.4.6.16 for system inertia in the management of the power system.

3.3.4.7 Automatic Generation Control

The Automatic Generation Control (AGC) shall be responsible for control of generating, load and demand side resources in both the economic sense, wherein the goal is to minimise real-time costs, as per scheduling and dispatch rules. AGC shall operate within the bounds of practical operating and security constraints, and in the regulation sense, wherein the goal is to minimise accumulated and instantaneous Area Control Error (ACE) such that frequency and tie-line performance criteria are met.

AGC is currently installed at most *Employer* and selected IPP generators including the *Employer's* wind farm. It shall be possible to, as per the installed AGC, in the future control loads such as boilers and other demand side options via AGC. The functionality shall exist to control groups of generators or loads via a single setpoint and/or bitstring of 32-bit command. It shall be possible to issue a single grouped message to each power station for every AGC control cycle, containing the combined AGC control requests to all the generators at the power station using the bitstring of 32-bit command.

Additional fields shall be provided to allow for user calculation and system monitoring in the real-time generation dispatch.

AGC shall be used to manage renewable sources as the renewable penetration increases.

Requirement Schedule:

i.	The standard TPSCM solution shall include the functionality defined in 3.3.4.7 for the Automatic Generation Control.

3.3.4.7.1 Execution Cycle

Requirement Schedule:

i.	The execution cycle requirements of the various AGC and generation dispatch functions shall be user definable.
ii.	Telemetry scan shall be possible every second.
iii.	Control cycle shall be possible every two seconds.
iv.	Real time dispatch based on scheduling and dispatch rules shall be possible at least every 5 minutes or on a major change in demand or supply, such as a generator output due to a trip.

3.3.4.7.2 Telemetry

Data shall be obtained from the following sources:

- Remote Terminal Equipment (RTE);

- Local I/O; and
- Data links with other EMS/DMS and/or SCADA.

The data required for AGC shall include at least:

- Tie-line MW;
- Generator gross MW, auxiliary MW and generator nett MW;
- Generator setpoint in gross/nett;
- Breaker status (telemetered or calculated status indication);
- Generator local/remote status for AGC;
- System frequency measurement and deviation;
- System accumulated time error measurement;
- Net scheduled interchange from the Interchange Transaction Scheduling (ITS);
- Generator limit settings in gross/nett;
- Generator frequency bias status indication; and
- Generator ramp rate.

The inverse of analogues shall be selectable for use within AGC.

Conversion of generator analogues from gross to nett and vice versa shall be possible by using either gross/nett tables or the calculation of auxiliary MW using measured generator gross MW and the measured generator nett MW.

Requirement Schedule:

i.	The input and/or output telemetry for the standard Automatic Generation Control shall include the data items defined in 3.3.4.7.2.

3.3.4.7.3 AGC Performance Criteria

Requirement Schedule:

i.	The ACE shall be maintained in accordance with the NERC Control Performance Standards CPS 1, CPS 2 and Disturbance Control Standard DCS 1 criterion, with an enterable Epsilon 1 and Epsilon 10.
ii.	The performance criteria shall include the latest NERC compliance standards.
iii.	The movement of AGC participants and energy balancing costs shall be minimised considering all constraints.

3.3.4.7.4 Area Control Error Calculation

AGC shall calculate a basic error signal, the ACE control. ACE shall be calculated as follows:

- ACE(control) = ΔP(filtered) + B(variable/fixed).Δf(filtered)
- In this formula, the meaning of the parameters is:
- ΔP(filtered) = Filtered power deviation from scheduled value
- B = Variable bias setting /fixed bias setting

- Δf(filtered) = Filtered frequency deviation from scheduled value
- Filter constants and bias settings shall be parameters.

Requirement Schedule:

i.	The area control error for the standard Automatic Generation Control shall be calculated as defined in 3.3.4.7.4.
ii.	It shall be possible to modify the calculation of the area control error.

3.3.4.7.5 Dynamic Target Frequency Calculation

The target frequency shall be automatically calculated as follows:

At 55 minutes past the hour, the contract for the current hour, Contract(hour), shall be compared to the contract for the next hour, Contract (hour + 1). The scheduled frequency shall then be set to the following values:

- f = F1 Hz if [ΔContract > 0 and ΔContract > X1] else
- = F2 Hz if [ΔContract < 0 and |ΔContract| > X2] else
- = F0 Hz

where

- Contract = Contract(hour + 1) - Contract(hour)

Contract is defined as scheduled generation. Contract values shall be computed as the sum of generator base-point schedules.

Target frequencies or offset from nominal, and MW settings for the above calculation shall be parameters. The target frequency shall also be configurable by the operator. All the parameters shall be operator enterable, with the following default values:

- Frequencies F0, F1 and F2. Default values: 50.0 Hz
- Energy (MWh) settings X1 and X2. Default values: 0.0 MW.

The scheduled frequency shall remain at its new value for the next sixty (60) minutes, but the operator can manually override it at any time. The target frequency shall be operator enterable. The management of the frequency measurements shall include the prioritisation of the available telemetry, switching between telemetry sources when bad quality is detected and time error correction.

Requirement Schedule:

i.	The target frequency for the standard Automatic Generation Control shall be automatically calculated as defined in 3.3.4.7.5.

3.3.4.7.6 Setpoint and Actual Output Feedback

Requirement Schedule:

i.	SCADA shall receive both setpoint and generation output telemetry from the generators, the former being the preferred measurement for AGC. Both values represent gross / nett generation. AGC shall use setpoint telemetry when available.
ii.	AGC shall automatically set the PLC frequency bias to zero when a generator uses the setpoint signal as feedback. Otherwise, if actual generation is used as feedback, the frequency bias shall be set to a reference value.

3.3.4.7.7 AGC Control Modes

Requirement Schedule:

i.	AGC shall provide the following control modes: flat tie line; flat frequency; tie line bias; and monitoring only.
ii.	If the AGC control function is suspended the system shall be available in a monitoring mode.

3.3.4.7.8 AGC Suspension

If any of the telemetered quantities, such as tie-line MW, time deviation or frequency, has a sustained telemetry failure, i.e., the failure exists for a user definable number of AGC cycles, then all further automatic control action shall automatically suspend the AGC mode. An alarm shall be raised in this case.

The following shall have two user enterable limits, i.e., warning and blocking:

- Tie line deviation;
- Frequency deviation; and
- ACE.

If a warning limit is exceeded, an alarm shall be issued. If a blocking limit is exceeded, an alarm shall be issued and AGC shall be paused.

The suspension of a function due to telemetry shall be limited to the direct reach of the measurement, such as a generating unit not being available for regulation control. The main reasons for a total AGC suspension are frequency unavailability, tie line measurement unavailability and excessive ACE. A pause and/or suspension matrix shall be used to define all the reasons for functions pause or suspension. Alarms shall be generated in both cases.

Reserve violations shall result in an alarm being generated.

Requirement Schedule:

i.	The criteria for Automatic Generation Control suspension shall include the criteria defined in 3.3.4.7.8.

3.3.4.7.9 Number of Generators

The cheapest set of generators, set x, shall be moved while the ACE is in the normal region and an additional set of generators, set y, when the ACE is in the assist region. The sizes of these sets, x and y, shall be configurable.

A regulation priority (any positive integer) can be assigned to each generator. The priority thresholds are specified for assist and emergency regions. Depending on the current ACE region (dead-band, normal, assist or emergency), all the generators with priorities lower than or equal to the appropriate threshold shall be moved first. Other generators shall be moved only if regulation from the first set proves insufficient.

A priority of zero can be entered for generators that should not contribute to regulation.

The bids received for the dispatch optimisation includes price versus MW for each generator as per the scheduling and dispatch rules.

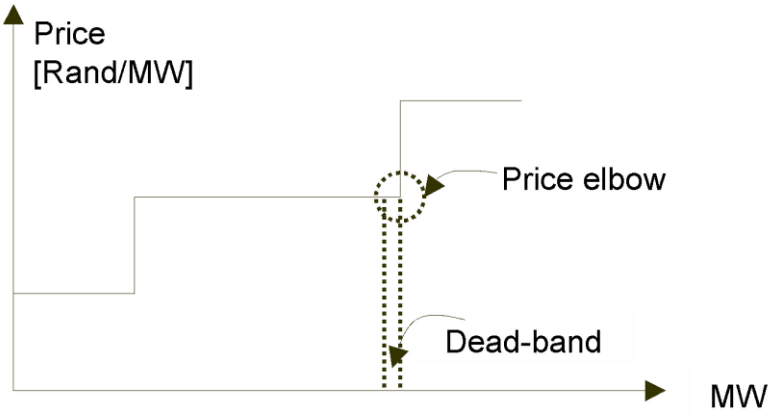

Figure 2: Generator Price Bid Curve

Regulation priorities shall be set automatically based on the information received for the generators. Two (2) user-enterable numbers N1 and N2 shall be provided. The cheapest N1 units will be assigned to priority one (1), the next cheapest N2 units will be assigned to priority two (2) and the remaining units to priority three (3). The ACE assist region priority threshold, for e.g., will be manually set to two (2).

To avoid operating at higher price levels when units require dispatching in the vicinity of price elbows, a user enterable MW dead-band shall be provided, and generators shall be maintained under this dead-band.

Price information shall be imported from the GDS through a marked-up or plain text file.

Every x seconds, the base load point of the generators in regulation mode shall be set to equal the feedback, which is either the actual output or setpoint. The integration is then performed and regulation mode generators are ready to move to any change in the ACE.

The base point adjustment function shall compute the difference between current system load and the sum of current generation basepoints, in particular current generation basepoint schedules. The function shall distribute this difference among units to modify their current basepoints. The distribution shall be based on participation factors different from those used for ACE regulation.

The AGC algorithm shall be capable of receiving basepoints from the GDS.

There shall be a merit order display created based on bid curves to be used for non-AGC dispatch.

Requirement Schedule:

i.	The current *Employer* specific logic and tuning of the function that will determine and / or limit the number of generators and loads available for control under the AGC, defined in 3.3.4.7.9, shall be retained.

3.3.4.7.10 PLC modelling

Requirement Schedule:

i.	When more than one (1) generator is modelled under a PLC, there shall be the option to calculate raise/lower commands or setpoints only for units selected for AGC.
ii.	The functionality to control only generators selected for AGC, as above, shall be extended to the simulator and advanced network applications.
iii.	A PLC shall be suspended from AGC when the regulating range is smaller than a user configurable value.

3.3.4.7.11 Multiple Control Areas

AGC shall cater for multiple control areas where generators and loads can be selected to a specific control area. Multiple control areas are required in order to represent external areas and the number of control areas modelled shall not be limited.

There shall be no limit to the number of utilities modelled as part of the *Employer* control area. Control areas shall be defined at database modelling time.

Each control area shall contain a set of plants (generators and/or loads) and interconnecting tie-lines. A control area shall be able to establish transactions (via interchange schedules) with other control areas and co-ordination centres. Full AGC functionality shall be available for each individual control area with any one selected as the control centre area allowing AGC.

AGC shall control frequency and / or interchanges for the *Employer* control area.

Requirement Schedule:

i.	Multiple AGC control areas, as defined in 3.3.4.7.11, shall be provided.

3.3.4.7.12 Special Generation Calculations

Special calculations are required for AGC. A calculated data function shall be available to develop most of these calculations. The calculated data function shall be used to periodically compute the following:

- Total nett generation (including and excluding renewables);
- Total generation per generation type;
- Total power system load (including and excluding *Employer* load, e.g., pumping and battery charging).

The GUI shall enable the addition and removal of generators from the calculation of totals during run-time.

A flexible monitoring tool shall be available to define different types of totals conditioned by types, owners, pumping, etc.

Requirement Schedule:

i.	A flexible monitoring tool shall be provided for generation calculation, as defined in 3.3.4.7.12.

3.3.4.8 Scheduling

3.3.4.8.1 Interchange Transaction Scheduling

Requirement Schedule:

i.	The automatic scheduling capability shall allow the entering of interchange schedules.
ii.	An Interchange Transaction Scheduling (ITS) program shall form part of the EMS functionality, which the operator can use to pre-schedule interchange transactions. This program shall calculate the nett scheduled interchange every AGC calculation cycle.
iii.	Input methods shall include marked-up and plain text, such as comma-delimited, files provided electronically.

3.3.4.8.2 Equipment Outage Scheduling

Requirement Schedule:

i.	In order to pre-schedule equipment maintenance outages and derations, an Equipment Outage Scheduling (EOS) shall be provided. The EOS shall be used to pre-schedule transmission line, transformer and generator outages, as well as generator derations.
ii.	The outage schedules shall be accessible to all functions in the system requiring the status of network and/or generation equipment in the future or in the past. Specifically, the schedule analysis functions and network analysis functions shall be able to obtain outage schedules from the EOS. For example, power flow shall be able to incorporate the outage schedules for outage feasibility studies.
iii.	The operator shall be able to easily enter, review, and modify schedules using an interactive GUI.
iv.	It shall be possible to exchange scheduled outages with external applications on the *Employer's* corporate network and write marked-up files to interface with the GDS.

3.3.5 Generation Dispatch System

Generation optimisation and dispatch is done according to the South African Grid Code: Scheduling and Dispatch Rules. The Generation Dispatch System shall be customisable to adapt to the change in Electricity Supply Industry as well as to any changes in the *Employer's* business model. The *Employer* has deployed a Generation Dispatch System which comply with the aforementioned requirements and shall evaluate options to optimise the investment.

3.3.5.1 Optimisation

3.3.5.1.1 Resources

The system obtains the optimal commitment and dispatch for all generators and demand side resources, for each hour of the dispatch day, based on the hourly expected demand, reserve requirements, non-dispatchable generator schedules, interconnection schedules, and the costs and availabilities of the dispatchable generators and demand-side resources.

The optimisation solution is over a seven (7) day period to incorporate the full pump storage cycle. The following power system elements is modelled for the IPS in order to give accurate low-cost solutions:

- Generators (internal and external to the *Employer*);
- Demand side resources including all energy storage resources; and
- Emergency resources (generation and demand side).

Option Schedule: Generation Dispatch System – Replacement

i.	The system shall be able to obtain the optimal commitment and dispatch for all generators and demand side resources, for each hour of the dispatch day, based on the hourly expected demand, reserve requirements, non-dispatchable generator schedules, interconnection schedules, and the costs and availabilities of the dispatchable generators and demand-side resources.
ii.	The generation dispatch optimisation shall be able to do the optimisation based on a price model (market based) as well as a cost model (central dispatch). The user shall be able to optimise over a seven (7) day period to incorporate the full pump storage cycle.
iii.	The following power system elements shall be modelled for the IPS in order to give accurate low-cost solutions: generators (internal and external to the *Employer*); demand side resources including all energy storage resources; and emergency resources (generation and demand side).

iv.	All models and configurations shall be ported from the Generation Dispatch System in use to the TPSCM.

Option Schedule: Generation Dispatch System – Integration

v.	The Generation Dispatch System in production shall be integrated as part of the TPSCM delivery on the new hardware with the same solver or optimisation solving engine in use.
vi.	The licenses and infrastructure required for the Generation Dispatch System migration and integration shall be delivered as part of the TPSCM solution.
vii.	The Generation Dispatch System in use, uses PLEXOS®, the energy simulation software, from Energy Exemplar and shall be integrated into the TSPCM solution.

3.3.5.1.2 Unit Commitment

The unit commitment minimises the total cost of generation required to meet the expected demand, conditioned by the reserve requirements and technical capabilities of dispatchable generators.

Option Schedule: Generation Dispatch System – Replacement

i.	The TPSCM shall optimise the commitment and dispatch for all generators and demand side resources, for each hour of the dispatch day, based on the hourly expected demand, reserve requirements, non-dispatchable generator schedules, interconnection schedules, and the costs and availabilities of the dispatchable generators and demand-side resources.
ii.	The total generation cost, considered by the optimiser, shall include the generation incremental cost for each scheduled generator, the start-up and shutdown cost for generators synchronised in that period and the cost of demand-side resources.
iii.	The optimiser shall co-optimise the *Employer* reserve model for regulating, instantaneous and 10-minute reserves with the energy dispatch schedule, constrained by the individual reserve requirements.
iv.	An optimal pumped storage cycle shall minimize the weekly generation cost while taking into consideration the pump storage cycle efficiency and the limits applied on the pond levels.
v.	Target pond levels shall be taken into account, i.e., the top pond must be full on Monday morning.
vi.	Reserve capability during the pumping mode shall be modelled.
vii.	Emergency resources, including interruptible load resources and emergency generators such as open-cycle gas turbines and the emergency level increments of thermal generators, shall not be included in the dispatch optimisation unless the user identifies an abnormal operating condition in particular hours, in which case these resources shall be included.
viii.	All generators shall provide a flexible/inflexible flag for every hour of the optimisation period. When a resource is flagged as inflexible in a particular hour, it shall be scheduled at its hourly availability. Additionally, this resource shall not be considered for any type of reserve. The inflexible flag shall override all other technical constraints, including ramp rates.
ix.	Dispatchable hydro generators shall have an hourly run flag for each hour of the optimisation period. Hydro generators shall only be considered for commitment and dispatch if the run flag is set to true. It shall be possible for the operator to override this flag.
x.	It shall be possible to flag a unit as non-commercial. Non-commercial units shall not be taken into account when attempting to satisfy reserve requirements.

xi.	It shall be possible to model emissions; fuel storage levels and targets; configurable dispatch intervals (the default is one (1) hour); forbidden zones of operation; and renewable energy related components.
xii.	It shall be possible for the user to enter constraints to override operational data. These constraints shall at least include the ability to: make a resource inflexible at a level below or equal to its provided hourly availability; alter the availability of a resource; and prevent a resource from being committed or decommitted.
xiii.	Penalty factors for all constraints shall be user configurable and allow for an audit trail to manage any changes.

Option Schedule: Generation Dispatch System – Integration

xiv.	The solution from the optimiser for the unit commitment in production shall be retained and integrated into the TPSCM.

3.3.5.2 Energy Limits

Energy limits is applicable at power station level and not generator level.

Option Schedule: Generation Dispatch System – Replacement

i.	Energy limits and constraints shall be considered when calculating the optimal commitment and dispatch.
ii.	Provision shall be made to accurately aggregate limits on generator level to station level.
iii.	A resource shall be able to indicate the energy limit, applicable to the dispatch day above which the system may not schedule additional energy from the power station or the demand side resource, as well as indicating the energy limit applicable to each of the six (6) days after the dispatch day.
iv.	For the full seven (7) days, the generator or demand side resource shall indicate the total energy limit above which the system may not schedule additional energy from the power station.

Option Schedule: Generation Dispatch System – Integration

v.	All pre-processing and calculations on energy limits in production shall be retained and integrated into the TPSCM.

3.3.5.3 Modes of Operation

The three (3) modes of operation for the optimisation of the generation dispatch include:

1) **Unconstrained mode**

   As specified in 3.3.5.1 and 3.3.5.2.

2) **Network and contingency constrained mode**

   In addition to the requirements for unconstrained mode, this mode includes a full IPS network model.

   The optimal dispatch as derived in the unconstrained mode is modified to alleviate network constraints, if any. If there is none, the solution is the same as that of the unconstrained mode.

This mode takes into account a set of given contingencies and modify the unconstrained solution in order not to violate any of the contingencies, as far as possible, within the constraint of acquiring a feasible solution.

This solution does violate any of the constraints enforced by the previous solutions, including but not limited to:

- Ramping and start up constraints;
- Minimum runtime and downtimes; and
- System reserve requirements.

It is possible to model different reserve zones, each with its own reserve requirements.

3) Near real-time mode

In addition to the network and contingency constrained mode, this mode of operation produces optimal solutions for the next fifteen (15) minutes (the time is configurable), from the current time, using the current State Estimator solutions and Short Term Load Forecast.

In this mode, new solutions are produced at five (5) minute (the time is configurable) intervals, but the export of the solution is initiated by the operator. There is a flag to enable the automated export of the solution.

Option Schedule: Generation Dispatch System – Replacement

i.	The unconstrained mode for the Generation Dispatch System shall conform to the requirements as defined in 3.3.5.1 and 3.3.5.2.
ii.	The network and contingency constrained mode shall include a full IPS network model. The optimal dispatch as derived in the unconstrained mode shall be modified to alleviate network constraints, if any. If there is none, the solution shall be the same as that of the unconstrained mode.
iii.	This network and contingency constrained solution shall not violate any of the constraints enforced by the unconstrained solutions, including but not limited to: ramping and start up constraints; minimum runtime and downtimes; and system reserve requirements.
iv.	It shall be possible to model different reserve zones, each with its own reserve requirements for the network and contingency constrained solution.
v.	The near real-time mode of operation shall produce optimal solutions for the next fifteen (15) minutes (the time shall be configurable), from the current time, using the current State Estimator solutions and Short Term Load Forecast.
vi.	Near real-time solutions shall be produced at five (5) minute (the time shall be configurable) intervals, but the export of the solution shall be operator initiated. There shall be a flag to enable the automated export of the solution.

Option Schedule: Generation Dispatch System – Integration

vii.	All modes of operation for the Generation Dispatch System in production shall be retained and integrated into the TPSCM.

3.3.5.4 Data Requirements

3.3.5.4.1 Standing Data

The following standing data applies to all generators:

- Power station name;
- Generator name;
- The fuel type of generator, e.g., coal-fired thermal, pumped storage, hydro;
- Maximum continuous rating (MCR) generated and MCR sentout of the generator; and
- Expected load factors.

In addition to the data listed above, the dispatchable generators provide:

- Minimum stable generation point (Mingen) of the generator;
- Startup ramp rates and costs of the generator defined as:
  - The time (h) since operation until which the generator is assumed hot, the associated startup ramp rate (MW/h) from a hot condition, the startup cost (R) for starting up from a hot condition and the associated lead time to synchronisation from a hot condition after an instruction,
  - The time (h) since operation until which the generator is presumed warm, the associated startup ramp rate (MW/h) from a warm condition, the startup cost (R) for starting up from a warm condition and the associated lead time to synchronisation from a warm condition after an instruction and
  - The associated startup ramp rate (MW/h) from a cold condition, the startup cost (R) for starting up from a cold condition and the associated lead time to synchronisation from a cold condition after an instruction;
- The minimum runtime (h) of the generator, i.e., the minimum time that the generator is prepared to generate;
- The minimum downtime (h) of the generator, i.e., the minimum time that the generator is prepared to stay off before being synchronised again;
- Startup ramp rate (MW/h), i.e., the rate at which the generator may be loaded between synchronisation and minimum stable generation point (Mingen);
- The loading ramp rate (MW/h), i.e., the rate at which the generator may be loaded between minimum stable generation point (Mingen) and the maximum continuous rating (MCR);
- The deloading ramp rate (MW/h), i.e., the rate at which the generator may be deloaded between MCR and Mingen;
- The shutdown ramp rate (MW/h), i.e., the rate at which the generator may be deloaded below Mingen;
- Certified capacity for Regulating Reserve (MW);
- Certified capacity for Instantaneous Reserve (MW);
- Certified capacity for 10 Minute Reserve (MW);
- Certified capacity for Supplemental Reserve (MW);
- Certified capacity for Emergency Reserve (MW); and
- A flag that indicates whether the generator is in commercial operation.

In addition to all, which are listed above, the dispatchable hydro generators provide:

- Cavitation (hydraulic instability) zones; and

- The energy equivalent of the minimum and maximum outflow from the water resource per day and per week respectively at power station level.

In addition to all, which are listed above, the dispatchable pump storage units provide:

- The maximum continuous pump rating for each generator;
- The minimum stable pumping point for each generator;
- Power station pump storage cycle efficiency; and
- Generation energy equivalent information for the:
    - Maximum and minimum level of the upper pond,
    - Maximum and minimum level of the lower pond,
    - Expected inflow into the upper and lower pond,
    - Allowed outflow from the upper and lower pond and
    - Required out flow from the upper and the lower pond.

The following standing data applies to all demand side resources:

- Demand side resource name;
- Location of the demand side resource;
- Maximum dispatch level of the resource;
- Resource dispatch costs;
- Energy equivalents for the maximum utilisation of the resource per day and per week;
- Certified capacity for Regulating Reserve (MW);
- Certified capacity for Instantaneous Reserve (MW);
- Certified capacity for 10 Minute Reserve (MW);
- Certification for Supplemental Reserve (MW); and
- Certification for Emergency Reserve (MW).

The standing data for Interconnections is:

- Interconnection name.

Option Schedule: Generation Dispatch System – Replacement

i.	The standing data for all generators shall include all of the following: power station name; generator name; fuel type of generator, e.g., coal-fired thermal, pumped storage, hydro; maximum continuous rating (MCR) generated and MCR sentout of the generator; and expected load factors.
ii.	The standing data for all resources shall conform to the data requirements in 3.3.5.4.1.
iii.	The standing data for Interconnections shall include the Interconnection name.
iv.	Classes of standing data modelled in the Generation Dispatch System and not defined in 3.3.5.4.1 shall be documented in terms of the scope of the requirement for each resource category.

Option Schedule: Generation Dispatch System – Integration

v.	The use of the migrated standing data in the TPSCM shall be consistent with the production Generation Dispatch System.

3.3.5.4.2 Availability Data

The following standard availability data is provided daily for all dispatchable generators:

- The hourly declared available capacity (MW), i.e., the maximum sentout to which the generator may be scheduled in the hour;
- A flag indicating whether the generator is flexible in that hour or inflexible to central dispatch;
- The Instantaneous Reserve Availability Indicator that indicates whether the generator is available to provide Instantaneous Reserve in the hour;
- The Regulating Reserve Availability Indicator that indicates whether the generator is available to provide Regulating Reserve in the hour;
- The 10 Minute Reserve Availability Indicator that indicates whether the generator is available to provide 10 Minute Reserve in the hour; and
- An hourly run flag that is only applicable to hydro units, since an energy constrained unit is only considered for commitment and dispatch if this flag is set.

Dispatchable hydro generators provide the same information as stated above.

Dispatchable pump storage generators provide additional information on the hourly declared available pumping capacity (MW), i.e., the maximum pumping capacity to which the generator may be scheduled in the hour.

Interconnection schedules provide a schedule of the expected imports for each hour of the dispatch day as well as indicative schedules for the six days after the dispatch day. The following availability data is provided:

- Interconnection name;
- The hour for the expected import and/or export; and
- The expected import and/or export schedule in the hour.

Dispatchable demand side resource submissions provide, in addition to the standard availability data, the expected hourly demand and energy limits.

Non dispatchable generators provide:

- The expected sentout (MWh) for each hour of the dispatch day as well as indicating the expected sentout for the six (6) days after the dispatch day; and
- The expected available capacity of the generator in the hour.

Option Schedule: Generation Dispatch System – Replacement

i.	Availability data required in the Generation Dispatch System algorithms shall hold onto the definition and scope defined in 3.3.5.4.2.
ii.	Classes of availability data required in the Generation Dispatch System and not defined in 3.3.5.4.2 shall be documented in terms of the scope of the requirement for each resource category.

Option Schedule: Generation Dispatch System – Integration

iii.	The use of the migrated availability data in the TPSCM shall be consistent with the production Generation Dispatch System.

3.3.5.4.3 Daily offers

The incremental cost of production is in the form of stepwise incrementing cost curve, with parameters set as:

- The minimum generation point of the generator (MW), which must be the same as the Mingen value for the generator from the standing data;
- The first elbow point (MW) which must be greater than or equal to the minimum generation point;
- The second elbow point (MW) which must be greater than or equal to the first elbow point;
- The third elbow point (MW) which must be equal to the MCR for the generator from the standing data and must be greater than or equal to the second elbow point;
- The Emergency Level 1 (EL1) point (MW) which must be greater than or equal to the third elbow point;
- The Cost Increment 0 (INC0), for the block of capacity between 0 MW and the minimum generation point that must be non-negative;
- The Cost Increment 1 (INC1), for the block of capacity between the minimum generation point and the first elbow point that must be non-negative;
- The Cost Increment 2 (INC2), for the block of capacity between the first elbow point and the second elbow point that must be greater than or equal to the Cost Increment 1 (INC1);
- The Cost Increment 3 (INC3), for the block of capacity between the second elbow point and the third elbow point that must be greater than or equal to the Cost Increment 2 (INC2); and
- The EL1 cost, for the block of capacity between the third elbow point and the EL1 point that must be greater than or equal to the Cost Increment 3 (INC3).

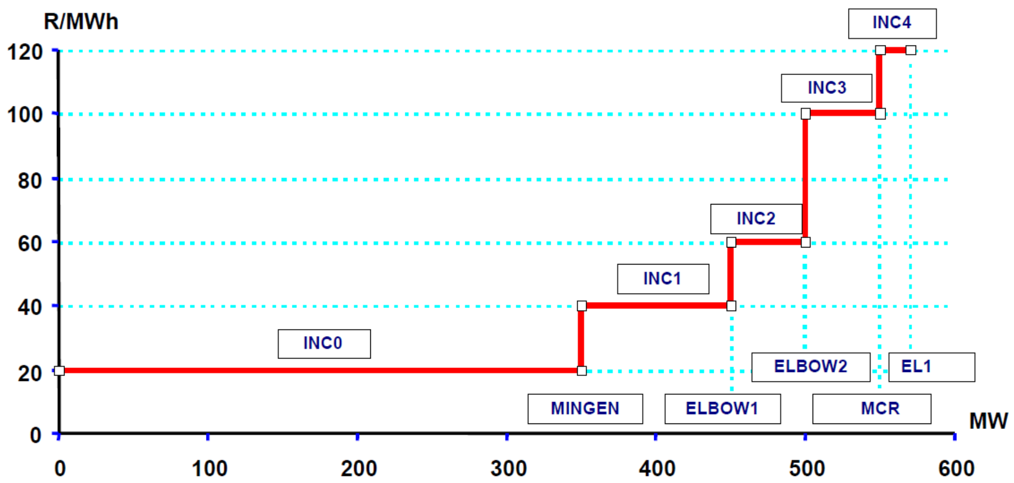

Figure 3: Typical Bid Curve

Option Schedule: Generation Dispatch System – Replacement

i.	The Generation Dispatch System algorithms shall use the information from the daily offers as described for a typical bid curve defined in 3.3.5.4.3.
ii.	Pre-processing rules to decide on the inclusion of an increment or not on the daily offers, required to improve performance and reduce high computational effort, shall be applied consistently to all optimisation cycles.

Option Schedule: Generation Dispatch System – Integration

iii.	The use of the migrated bid curves in the TPSCM shall be consistent with the production Generation Dispatch System

3.3.5.5 User Modifiable Input

Any user modified input data shall have an audit trail and shall be transferred back to the original data source. At least the following information shall be user modifiable:

The user modifiable input data include:

- Optimiser parameters:
  - The number of days for which the optimisation is done, typically between one (1) and seven (7) days and
  - Penalty factors associated with constraints;
- Dynamic input data:
  - Dispatch area level -
    - The load forecast,
    - The reserve requirements and
    - The system emergency situation flag,
  - Generator Level -
    - Generator availabilities, meaning all hourly generator parameters,
    - Generator initial status and
    - Generator constraints.

Option Schedule: Generation Dispatch System – Replacement

i.	Any user modified input data shall have an audit trail and shall be transferred back to the original data source.
ii.	The user modifiable input shall at least include the information defined in 3.3.5.5.
iii.	It shall be possible to reconstruct the data series to any date and time selected by the operator.
iv.	Any restrictions to the modification of data in the Generation Dispatch System shall be documented and mitigated through functionality which will produce a robust and accurate solution.

Option Schedule: Generation Dispatch System – Integration

v.	The integration of the production Generation Dispatch System into the TPSCM shall not reduce the integrity of the user modifiable data and audit trail.

3.3.5.6 Outputs and Reporting

The output from the Generation Dispatch System include:

- Hourly energy schedule for each resource;
- Hourly schedule for each resource for each type of reserve; and

- Hourly availability of each generator.

The reports generated by the Generation Dispatch System include:

- System summary reports i.e., hourly total cost and hourly marginal cost;
- Adequacy report indicating the expected demand, reserve requirements, the capacity available to meet the demand, capacity allocated to reserves and the total expected sentout; and
- Expected storage levels.

Option Schedule: Generation Dispatch System – Replacement

i.	The results from the Generation Dispatch System shall include at minimum the output and reports defined in 3.3.5.6.
ii.	The output and reports from the Generation Dispatch System shall be user modifiable.
iii.	The archiving and backup of the output data and reports shall not result in any unavailability of the Generation Dispatch System.
iv.	The results from the Optimal Power Flow and the Generation Dispatch System shall be consistent in the TPSCM solution.

Option Schedule: Generation Dispatch System – Integration

v.	The integration of the production Generation Dispatch System into the TPSCM shall not modify any of the output data and reports.
vi.	The results from the Optimal Power Flow delivered with the TPSCM shall be consistent with the production Generation Dispatch System integrated as part of TPSCM solution.

3.3.5.7 System Architecture

The Generation Dispatch System architecture is consistent with the requirements for rest of the TPSCM.

Option Schedule: Hardware – Generation Dispatch System

i.	The production and disaster recovery environment for the Generation Dispatch System shall have dual redundancy for the application servers, data gateways and optimisers.
ii.	The development and training environment at minimum shall cater for a single configuration.
iii.	The archiving and backup of the output data and reports shall not result in any unavailability of the Generation Dispatch System.
iv.	The architecture of the Generation Dispatch System shall migrate as part of the TPSCM solution.

Option Schedule: Generation Dispatch System – Integration

v.	The integration of the production Generation Dispatch System into the TPSCM shall be transparent to the operator on the Graphical User Interface.

3.3.5.8 Reserves Modelling

Reserve contracts are imported into the EMS from the Generation Dispatch System.

Option Schedule: Generation Dispatch System – Replacement

i.	Additional reserve categories other than the categories already defined in 3.3.5.8 shall be accommodated in all reserve modelling.
ii.	For all of the reserve types described in 3.3.5.8, except for reactive power reserves, the contracted reserve shall be used as a limit on the reserve that generators can potentially provide, i.e., generator contribution to reserve = min { contract value, calculated reserve }
iii.	Contracted Regulation Reserve shall be the amount of capacity available under AGC that is contracted for regulation and fully activated within ten (10) minutes. Regulation reserve for generators under AGC, which are contracted for regulation, shall be computed separately, per region, in the raise and lower directions.
iv.	Regulation Reserve, for all generators under AGC shall be computed separately in the raise and lower directions. The regulating reserve, per region, shall be compared to the requirement value and deficiencies shall be alarmed.
v.	Instantaneous Reserve shall be the amount of capacity that can respond in ten (10) seconds to changes in frequency and is available under local control at the generator and load, i.e., primary frequency control. The contracted Instantaneous Reserve shall be imported into the EMS for monitoring. The available contracted Instantaneous Reserve shall continuously be calculated from the real-time data of the generators and loads while taking into consideration the limits that apply to the provision of this service, such as the maximum and minimum capacity. The total Instantaneous Reserve shall be compared to the requirement value and deficiencies shall be alarmed.
vi.	The 10-minute Reserve shall be the contracted reserve not under AGC control and primary frequency control that can respond within 10 minutes. Contracted 10-minute Reserve shall be imported to the EMS. The available contracted 10-minute Reserve shall continuously be calculated from the real-time data of the generators and loads while taking into consideration the limits that apply to the provision of this service, such as the maximum and minimum capacity. The total 10-minute Reserve shall be compared to the requirement value and deficiencies shall be alarmed.
vii.	Supplemental Reserve shall be the capacity used to reduce short-term risk and ensure acceptable day ahead risk. This reserve is available for at least two hours. The contracted Supplemental Reserve shall be imported into the EMS for viewing and monitoring.
viii.	Emergency Reserve shall include interruptible loads, generator emergency capacity (EL1), and gas turbine capacity which shall be fully activated within 10 minutes. The contracted Emergency Reserve shall be imported into the EMS for viewing and monitoring.
ix.	Reactive Power Reserves is the reactive power from transmission equipment on the IPS, such as capacitor banks and inductors that can be switched in for voltage stability. Reactive Power Reserves shall be computed by the State Estimator.

Option Schedule: Generation Dispatch System – Integration

x.	The integration of the production Generation Dispatch System into the TPSCM shall not alter the existing definition or application of the reserves modelled.

3.3.5.9 Electronic Dispatch System

The Electronic Dispatch System (EDS) allows the dispatcher to manually instruct resources to change output, as well as communicate schedules generated by the GDS to different participants. In accordance with the South African Grid Code: Scheduling and Dispatch Rules, all instructions are captured electronically for audit and financial balancing purposes. In this context, a schedule generated by the GDS is considered to be a mass set of instructions.

Option Schedule: Electronic Dispatch System – Replacement

i.	The EDS shall support the role of the loading operator as defined in 3.3.5.9.
ii.	The EDS shall support dispatching participants to comply with the latest scheduling and dispatch rules as per the South African Grid Code: Scheduling and Dispatch Rules.
iii.	The EDS shall be customisable with different demand side products based on specific product criteria and contracts.
iv.	The system shall be sized to manage up to 100 participant and up to 500 resources.
v.	The logical access to stored historical information for review and analysis shall be consistent within the TPSCM.

Option Schedule: Electronic Dispatch System – Integration

vi.	The integration of the production Electronic Dispatch System into the TPSCM shall not alter the existing process flows and communication with the participants.

3.3.5.9.1 Instructions

Option Schedule: Electronic Dispatch System – Replacement

i.	Instructions shall be sent from the operator interface to participants for one or more resources, for the current hour and/or for future hours.
ii.	Instructions shall take the form of a single instruction from the operator, to a single resource, or large number of instructions to all participants (intra-day schedule).
iii.	An hourly set of instructions for each resource shall be maintained for at least 24 hours. This implies a schedule of instructions from now, until midnight of the following day shall be available.
iv.	The first instruction to each participant shall be the day-ahead schedule which shall be sent on the day prior to the day of operation.
v.	An instruction shall be valid for a single hour, so there should be at least one instruction for every hour on the day of operation.
vi.	When an instruction changes during the hour, only the latest instruction shall be shown to the participant and the operator, but previous instruction shall be captured in order to calculate instructed energy.
vii.	When sending a single instruction the following information shall be captured: • time of the instructions; • new required MW level or MW reduction required for loads; • time at which the new level should be reached, capped by the ramping capability of the resource or participant; and • an optional reason for the dispatch instructions, especially relevant when starting up or shutting down resources.

viii.	When sending an intra-day schedule, the following information shall be captured: • time new schedule is accepted; • hourly schedule from the hour following the current hour, to midnight on the following day; and • reason for accepting the new the intra-day schedule.

Option Schedule: Electronic Dispatch System – Integration

ix.	The set of instructions from the production Electronic Dispatch System shall be available in the TPSCM for the required operating and control by the loading operator.

3.3.5.9.2 System Interfaces

The EDS interfaces with participants and other systems. Some of the participants are on the *Employer's* corporate network – external to the TPSCM operational network – and some are external to the *Employer's network*. The EDS interfaces with the following participants:

- *Employer's* power stations;
- Independent Power Producers (IPP); and
- Aggregators (demand and / or supply side).

EDS interfaces and data flows are required with the:

- Energy Management System;
- Settlement systems; and
- Other components of the Generation Dispatch System.

Each instruction can be one of two states, 'acknowledged' (ACK) or 'not acknowledged' (NACK). Instruction states are centrally and uniquely maintained, to avoid the possibility of out of sync states between operator and participant. The state of the instruction, shown on the operator and / or participant display, is only updated once the central state is updated. The state diagram below indicates how the allowed states can change:

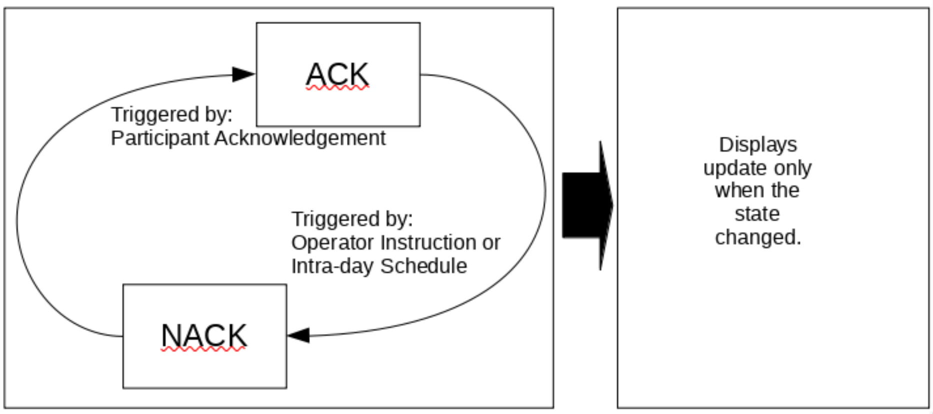

Figure 4: Electronic Dispatch System (EDS) flow diagram

Option Schedule: Electronic Dispatch System – Replacement

i.	Each instruction shall be one of two states, 'acknowledged' (ACK) or 'not acknowledged' (NACK).

ii.	Instruction states shall be centrally and uniquely maintained, to avoid the possibility of out of sync states between operator and participant.
iii.	The state of the instruction, shown on the operator and / or participant display, shall only be updated once the central state is updated.
iv.	Access to the EDS shall be the same for all participants defined in 3.3.5.9.2.
v.	The requirements for the system interface are defined in 3.3.7.

Option Schedule: Electronic Dispatch System – Integration

vi.	The integration of system interface from the production Electronic Dispatch System shall retain all data sets required for the operating and control by the loading operator.
vii.	The system interface shall conform to the requirements defined in 3.3.7

3.3.5.9.3 User Interfaces

The EDS has at least two (2) distinct user interfaces:

1) Participant

- The participant interface displays hourly instructions for the current hour, and future hours up to at least midnight on the day after the operating day.
- The display draws the attention of the participant to any changed instructions with colour and sound.
- The participant can acknowledge new instructions, or groups of instructions (for instance, an intra-day schedule will be instructions for all future hours).
- The participant can issue an “Acknowledge All”.

2) Loading operators

- The user interface for the loading operator displays the current status for all participants and resources.
- The loading operator can issue instructions to individual resources.
- Unacknowledged instructions from the loading operator is highlighted.
- System information, such as frequency (hz), direction of load changes, merit order stacks and reserve availability is available on the EDS displays.
- The loading operator can implement a new intra-day schedule from the user interface.

Option Schedule: Electronic Dispatch System – Replacement

i.	The EDS shall have at least two (2) distinct user interfaces required for the participants and the loading operator as defined in 3.3.5.9.3.
ii.	There shall be no overlap in permissions, i.e. no participant shall be able view the loading operator user interface. In addition, participants shall not be able to access information of other participants.

Option Schedule: Electronic Dispatch System – Integration

iii.	The integration of graphical user interface from the production Electronic Dispatch System shall be consistent and seamless to the loading operator.

3.3.5.10 Load Forecast

A Medium Term Load Forecast (MTLF) and Short Term Load Forecast (STLF) have a mean absolute percentage error (MAPE) of less than 1.4%. The interval for the Short Term Load Forecast is one (1) minute. The load forecast shall be compared against actual load in real-time.

Requirement Schedule:

i.	A Medium Term Load Forecast (MTLF) and Short Term Load Forecast (STLF) shall have a mean absolute percentage error (MAPE) of less than 1.4%.
ii.	The interval for the Short Term Load Forecast shall be one (1) minute.
iii.	The load forecast shall be compared against actual load in real-time and graphically presented.
iv.	The use of an external Medium Term Load Forecast and Short Term Load Forecast, loaded into the TPSCM, shall be transparent to operator.

3.3.5.11 Custom Logs and Interfaces

The EMS is the primary interface of the TPSCM for all operating and control instruction issued to the Interconnected Power System.

Requirement Schedule:

i.	The TPSCM shall provide the loading operator with the following custom logs: all dispatch instructions; reasons for load losses; and reasons for inflexibility.
ii.	Operators shall raise/lower the required voltage (ΔV) for a selected power station through a change in the setpoint.
iii.	A post event analysis shall be generated to report the performance of the power station for voltage control.
iv.	All information in the EMS, including information transferred in from the GDS, shall be available to generate audit and management reports on operator actions.
v.	Management and performance reports shall be generated on the voltage control.

3.3.6 Control Centre Wide Area Monitoring System

3.3.6.1 System Architecture

Option Schedule: Hardware – Control Centre Wide Area Monitoring System

i.	The production and disaster recovery environment for the Control Centre Wide Area Monitoring System shall be dual redundant as per 3.2.1.2.2.
ii.	All data flow shall adhere to the cyber security standards defined in 3.2.3.
iii.	Operators shall be able to create a local offline copy of data streams from the historian for analysis.

iv.	The hardware, firewalls, historian and software shall be able to handle data streams with 20ms resolution for all PMUs.
v.	The WAMS system shall have six terminal stations at PCC and a terminal at SCC to monitor the performance of the network.

3.3.6.2 Power System Awareness

Option Schedule: Control Centre Wide Area Monitoring System – Replacement

i.	Phasor measurements data shall improve situational awareness through advanced visualisation tools integrated seamlessly to the operator in the Graphical User Interface.
ii.	Post mortem analysis, after system disturbances, shall be enhanced by the phasor measurements data and associated analytics.
iii.	The Wide Area Monitoring System shall provide automated event recording and analysis.
iv.	The quality of the real-time State Estimator solution shall be improved with high accuracy data classes from phasor measurements.
v.	Model benchmarking through parameter estimation (steady state and dynamic) shall be available through phasor measurement data.
vi.	The utilisation of phasor measurement data and associated analytics shall reduce the power system restoration time.
vii.	The phasor measurements shall be used to monitor and predict the effective regional and system inertia
viii.	The calculations and / or formulas for the effective system inertia shall be available to further study the impact of the loss of load on the system inertia. The calculation of the system inertia and the input parameters used shall assist in the forward planning based on scheduling of units and planned outages and also the contribution from the neighbouring countries based on the bids.
ix.	It shall be possible to configure the system inertia calculation parameters.
x.	The calculation of the system inertia shall assist in the decision to curtail renewable generation rather putting units in cold reserve and / or two shifting based on the level of required inertia and primary response from the cheaper coal units.
xi.	The utilisation of common services in the architecture of the TPSCM, such as the historian, shall not prevent the logical and physical isolation of the Wide Area Monitoring System as part of disaster management strategy.

Option Schedule: Control Centre Wide Area Monitoring System – Enhancement

Each of the optional enhancements shall be available individually and alternatively as a bundled solution.

i.	The Wide Area Monitoring System shall support a network state estimation using linear measurement functions.
ii.	The integrity of the Interconnected Power System shall be enhanced by real-time control options available through the Wide Area Monitoring System.
iii.	The Wide Area Monitoring System shall assist with: • Estimations of system strength and line parameters • Wide area situational awareness; • Monitoring of the phase angles and grid stress;

	• Voltage stability monitoring; • Detection, analysis and monitoring of oscillation stability; • Frequency stability monitoring; • Analysis and monitoring of power flows and inter-area power transfers; • Detection and analysis of deviations in generation and/or load; • Island detection and resynchronisation; • Improving data integrity; and • Improved alarm processing.
iv.	Adaptive protection and special protection systems shall benefit from the phasor measurements.
v.	Phasor measurement data shall improve Small Signal Stability monitoring.

3.3.6.3 Phasor Data Concentrator

Option Schedule: Control Centre Wide Area Monitoring System – Replacement

i.	The Phasor Data Concentrator shall collect data from remote PMUs, align the data to a time sequence and serve as the data acquisition service to the rest of the WAMS.
ii.	Even if all synchronised measurement analytics and archiving are stand-alone / isolated in the WAMS, relevant data shall be transferred into the Energy Management System, Situational Awareness and shall enhance the functionality of the Operator Training Simulator.
iii.	Data transferred from the WAMS to the EMS shall adhere to 3.2.1.2.7.

3.3.6.4 Data Acquisition and Exchange

3.3.6.4.1 Power Quality Equipment

The standards for power quality records and analysers are the following:

- Power quality measurement – IEC 1000-4-30 Ed 3.0 ((Class-A)
- Harmonic and inter-harmonics – IEC 61000-4-7 (Class-1)
- Flicker meter – IEC 61000-4-15 (Class-F1)
- SCADA protocol – Modbus over IP and IEC 61850.

Option Schedule: Power Quality Integration

i.	The TPSCM shall be able to connect to power quality analyser, such as the Vecto II® power quality analyser and the Vecto III® multifunction power quality analyser from CT LAB (Pty) Ltd.
ii.	The TPSCM shall be able connect to power quality recorders with permanent GPS and precision time protocol (PTP) time synchronisation.
iii.	It shall be possible to import raw data files received from power quality recorders into the TPSCM. The TPSCM shall be configurable to retain the sampling rate of the imported file regardless of the default sampling rate configured in the TPSCM.

3.3.6.4.2 Substation class Phasor Data Concentrators

Substation class Phasor Data Concentrators (SPDC) manage multiple Phasor Measurement Unit (PMU) data streams at substation level. All substation connections from the PMU to the SPDC are 100Base fibre optic Ethernet. The standards for communication to PMUs and SPDC shall include (hereafter referred to as):

IEEE C37.118.2 IEEE Standard for Synchrophasor Data Transfer for Power Systems

Option Schedule: Control Centre Wide Area Monitoring System – Replacement

i.	The SPDC shall merge all PMU data and connect to the communication network via a serial or an Ethernet interface.
ii.	Data shall be streamed with at least 128kbits/sec circuits available from transmission stations to PCC and SCC
iii.	Remote access to PMU/SPDCs for the download of configuration files/settings shall be possible.
iv.	Phasor Data Concentrator/s (PDC/s) shall handle the data acquisition of raw data and storage thereof in a real-time synchronised phasor measurements database for use by all applications.
v.	The PDC shall be capable of interfacing with the PMU/SPDCs that support the IEEE C37.118.2-2011 message framework for serial or IP protocols such as UDP/TCP IP.
vi.	The full suite of IEEE C37.118.2-2011 message frames, which includes data, configuration, header, and command frames shall be supported. Commands, as specified by the standard, shall include send configuration/header file, start data transmission and stop data transmission.
vii.	The general reporting rate shall be configurable to the rates as stipulated in the IEEE C37.118 standard including an expected rate of a hundred and twenty (120) frames/sec. The default rate shall be fifty (50) frames/sec. It shall be possible to migrate the TPSCM to meet higher resolution samples during the life cycle of the TPSCM.
viii.	Interfacing to PMU/SPDCs of varying reporting rates shall be possible, even for those with the option available of interpolated phasor data for PMU/SPDCs reported at rates less than the PDC set rate.
ix.	The PDC shall support communications and management of more than a hundred (100) PMU/SPDCs reporting a minimum of twenty-five (25) phasor data channels per PMU/SPDC. The full declared capability shall be at the highest data reporting rates of fifty (50) frames/sec for IP and serial communications or a combination thereof.
x.	The architecture of the PDC shall be scalable to allow for future growth of the system where multiple PDCs may be required.
xi.	A connectivity manager shall manage the connection of IEEE C37.118.2-2011 compliant PMU/SPDCs configured for serial or ethernet (TCP/IP or UDP) communications. The configuration file for the connectivity manager shall include the PMU location, identifier, data format, as well as the communications connection settings for serial RS232 and Ethernet ports.
xii.	TCP and UDP shall support the default port sockets where default port numbers shall be 4712 for TCP and 4713 for UDP, but in all cases, the user may set the port numbers as desired. Serial transmission shall support the standard serial communications port options available with the windows interface.
xiii.	The user shall be capable to deactivate and reactivate the scanning of a given PMU/SPDC. The connectivity status of all PMU/SPDCs shall be clearly visible in a global view.
xiv.	Each PMU/SPDC being streamed shall have an individual view that indicates the current PMU/SPDC configuration, header file data (read from the IED) and a real-time data frame viewer indicating relevant frame information and statistics.

xv.	A real-time view of raw PMU data such as voltage, current, frequency, real power, reactive power, status indications or other quantities as contained in the data frame shall be available. An option to view phasors and system quantities in appropriate graphical formats shall be available to the user.
xvi.	All Application Protocol Data Units (APDU) as listed in the IEEE C37.118.2-2011 specification shall be implemented.
xvii.	No restriction shall exist to integrate the PMU/SPDC products from any supplier.
xviii.	Data quality shall be reported up to historian level and shall be included in the archived data.
xix.	The synchronised data process shall support simulated data files for testing purposes.
xx.	Simultaneous streams from a PMU/SPDC to the PCC and SCC shall not result in ambiguity in the TPSCM, more specifically in Control Centre Wide Area Monitoring System.
xxi.	The TPSCM shall interface to both P and M Class Phasor Measurement Units (PMU).
xxii.	The TPSCM shall be backward compatible for all standard versions from IEEE C37.118-2005.

3.3.6.4.3 Energy Management System

Option Schedule: Control Centre Wide Area Monitoring System – Replacement

i.	An alarm shall be forwarded to the standard Energy Management System alarm application and TPSCM monitoring tools when PMUs or SPDCs or PDCs are offline.
ii.	WAMS shall be capable of interfacing with the other TPSCM data acquisition servers that operate via the IEC 60870-5-101 protocol and/or IEC 60870-5-104 protocol and/or Inter-Control Centre Communications Protocol (ICCP / IEC 60870-6-503). Baud rates for serial communication of between 1200 bps and 19200 bps inclusive shall be supported.
iii.	The implementation of IEC 60870-5-101 and/or IEC 60870-5-104 shall be consistent with 3.3.4.1.1.
iv.	Information exchange via the historian to the Operator Training Simulator, Energy Management System and Generation Dispatch shall be possible.

3.3.6.5 Data Management Process

Option Schedule: Control Centre Wide Area Monitoring System – Replacement

i.	A data management function shall ensure that data items available from PMU and/or SPDCs in IEEE C37.118 format are configured and mapped for use in the synchronised phasor measurements database by the Wide Area Monitoring System.
ii.	The data items to be mapped shall include the voltage and current phasors, frequency, calculated quantities, symmetrical components, status indications as well specific PMU attributes such as PMU identifier and state.
iii.	The data management shall support the following types of data processing i.e., synchronised phasor data, status indication, calculated and simulated data.
iv.	It shall be possible to scale the phasor voltage and current measurements in terms of magnitude or angle. Scaling of measurements shall be executed by users with analyst or maintenance permissions at the PDC data acquisition level, without a need for a full synchronised measurements database update.

v.	A GPS or Simple Network Time Protocol (SNTP) time synchronisation shall be available for precise local time stamping of input data, application data, events, alarms and output data. The time synchronised data shall be available to the rest of the TPSCM.
vi.	Data quality for synchronised data and calculated data shall clearly indicate the status of the measurement.
vii.	The data management shall make provision for data encoding in polar and rectangular formats with scaling and offsets defined for both integer and reals.
viii.	Marked-up or plain text file-based export of PMU data and results from analytics shall be available for integration of third (3rd) party software.

3.3.6.5.1 Analogues

Option Schedule: Control Centre Wide Area Monitoring System – Replacement

i.	The management and functions available for analogues shall be consistent with the analogue processing for the EMS.

3.3.6.5.2 Status Indications

Option Schedule: Control Centre Wide Area Monitoring System – Replacement

i.	A change-of-status bit reported via an IEEE C37.118.2-2011 message shall be configurable as a user alarm for display or further processing.
ii.	It shall be possible to link any status indication to any destination for display.

3.3.6.5.3 Calculated Data

Option Schedule: Control Centre Wide Area Monitoring System – Replacement

i.	The calculated data function shall be used for calculations that shall be performed at a rate close to the fastest reporting rate.
ii.	The frequency of calculations shall be user definable on an individual calculation basis.
iii.	Calculations shall include rectangular to polar conversions and both values shall be displayable on all the workstations.
iv.	Engineers and data modellers shall define the custom calculations offline to retain the master repository of all calculations.
v.	The source and destination of the calculation shall be unrestricted. The results of the custom calculations shall be modelled as alarms in the Energy Management System.

3.3.6.6 Small Signal Stability Assessment

Option Schedule: Control Centre Wide Area Monitoring System – Replacement

i.	Small Signal Stability Assessment (SSSA) based on real-time phasor measurement data shall be provided to monitor, track and assess local and inter-area low frequency oscillatory conditions in real-time, based on selected power system signals.

ii.	All workstations shall have access to the graphical output of the SSSA. All output shall be available for display through a standard web browser.
iii.	The SSSA shall have a real-time and study mode.
iv.	The study mode shall allow the selection of historical data or other user data for analysis and playback whilst the real-time analysis shall still be active/operational. The study mode shall also be available in the Operator Training Simulator.
v.	The ranking of algorithms within the SSSA shall be well documented and explained.
vi.	At minimum, the SSSA shall function with single-phase power system signals, e.g., a single-phase voltage and current PMU channel from a user selectable PMU location and shall process data to characterise the observable modes of oscillation. All PMU devices and channels shall have the capability to perform the dynamic characterization of the observable modes of oscillation.
vii.	Customisable post processing ability shall include default variables and user defined rules. All input data, algorithm parameters and analysis output and alarms shall be available in graphical, tabular and database format for processing.
viii.	The SSSA shall provide the operator with alarm information through the alarm application of the Energy Management System. User configurable alarming thresholds for mode damping shall be available. The alarms shall also be made available for processing by other applications.
ix.	SSSA shall identify the dominant and poorly damped modes from selected power system signals.
x.	Reporting of the mode frequency, mode amplitude, mode damping, mode phase, participation factor for the selected power signal shall be available.
xi.	The SSSA shall be capable of reporting up to five dominant modes per power system signal.
xii.	Spectral or locus plots of frequency modes versus time or damping ratio/decay time as well as mode scatter plots and histograms to indicate a mode's behaviour over a specific time period shall be user configurable.
xiii.	All analysis output data and alarms shall be stored in the historian.

3.3.6.7 Alarm and Event Management

Option Schedule: Control Centre Wide Area Monitoring System – Replacement

i.	All events or risk identified in the WAMS shall have configurable violation thresholds for alarming purposes. The alarm and event management shall be consistent through the TPSCM.
ii.	Violation thresholds shall be specifiable over a user defined time period, e.g., a rate of change of frequency that persists over a specified time interval.
iii.	Displays shall support real-time visual (colour coded) and textual alarming upon violation of pre-defined thresholds and rate of change of key metrics.
iv.	Alarm management shall be configurable such that important alarm conditions may be reported in a clear, concise, and timely manner while the less important alarms are recorded for later analysis and action.
v.	The objective is to ensure that the operator is not overwhelmed with so much data that it is difficult to recognise the existence of serious alarm conditions and to isolate the causes.
vi.	All output shall be available for display through a standard web browser consistent with the rest of the TPSCM.
vii.	It shall be possible to forward all the alarms, events and/or status received or generated in the PDC from the PMU to the Energy Management System alarm application.

viii.	It shall be configurable to auto delete alarms, events and/or status forwarded to the Energy Management System alarm application.

3.3.7 Data Gateway

Requirement Schedule:

i.	The Data Gateway shall be implemented using secure protocols and secure transfer methods.
ii.	All data transferred through the Data Gateway shall provide an audit trail in the recipient application within the TPSCM.
iii.	Audit trails for data exchange shall be available in the historian or archive server or the SIEM.

3.3.7.1 Energy Management System

Requirement Schedule:

iv.	Data exchange into the Energy Management System from applications external to the TPSCM shall be through the Data Gateway.
v.	Data transfer shall not transverse more than one security zone during exchange.
vi.	The data shall be consistent between the PCC and SCC.
vii.	Applications requiring data external to the TPSCM shall access the Data Gateway in the same security zone as the application itself.

3.3.7.2 Generation Dispatch System

Option Schedule: Generation Dispatch System – Replacement

i.	Data exchange into the Generation Dispatch System from applications external to the TPSCM shall be through the Data Gateway.
ii.	The production GDS shall only access data available on the production Data Gateway for the active site. In addition, GDS applications shall only access data from a Data Gateway residing in the same security zone as the GDS application itself.
iii.	Data transfer shall not transverse more than one security zone during exchange.

Option Schedule: Generation Dispatch – System Integration

iv.	The integration of data transfer for the integrated Generation Dispatch System shall be consistent with the current production system.
v.	The Generation Dispatch System integration solution for the Data Gateway shall be implemented on the common platform used for the Data Gateway for the Energy Management System.

3.3.7.2.1 Real-time Dispatch and Operating Plan

Requirement Schedule:

i.	Where the data transfer for the real-time dispatch and operating plan originates from a source external to the TPSCM and is transferred through the production Data Gateway the activity shall be logged with a clear audit trail of data loaded.

3.3.7.2.2 Electronic Dispatch System

Option Schedule: Electronic Dispatch System – Replacement

i.	Instructions from the Electronic Dispatch System shall not transverse more than one security zone at a time.

Option Schedule: Electronic Dispatch System – Integration

ii.	The data transfer for the production Electronic Dispatch System shall be migrated to the TPSCM.

3.3.7.2.3 Generation Information System

The Generation Information System is an existing system external to the TPSCM containing the following types of information:

- generator and demand side standing data;
- load forecasting and renewable forecasting information;
- generator and demand side availability;
- generator and demand side pricing information; and
- generator and demand side schedules.

Requirement Schedule:

i.	The data transfer between the TPSCM and the Generation Information System shall be through the Data Gateway.
ii.	Data transfer shall not transverse more than one security zone during exchange.

3.3.7.2.4 Load Forecast

Requirement Schedule:

i.	Audit trails and logs shall be provided for all load forecast data exchanges.
ii.	Data transfer shall not transverse more than one security zone during exchange.

3.3.7.3 Situational Awareness

Requirement Schedule:

i.	All data not residing within the TPSCM such as meteorological data required for the Situational Awareness shall be transferred into the TPSCM using the Data Gateway servers.
ii.	The Situational Awareness applications shall access only the Data Gateway on the control network for information from external systems.

3.3.8 Historical Information System

The Historical Information System (HIS) shall be deployed on the latest release of a preferred open source relational database, e.g., PostgreSQL, MariaDB, MySQL community edition to enable the *Employer* to take benefit of recent improvements as soon as possible and minimise future major updates.

An audit trail of changes made to the HIS database shall be maintained and made available for display and printout. The audit trail shall identify every change made to the HIS database content and structure, the time and date of the change, and uniquely identify the party making the change. The audit trail shall include both before and after values of all content and structure changes. Audit trails shall be kept for the same time period as the data.

The HIS shall collect near real-time data at the same frequency as that the real-time system collects the information.

The HIS shall store a minimum of five (5) years of half hourly, hourly, weekly, monthly yearly and ad hoc information and thereafter archived for five (5) years. The database shall store a minimum of twenty-four (24) months of information with a time interval of less than half hourly and thereafter user selected information archived for five (5) years.

The HIS shall be provided with a hot standby and facilities for fail-over and fail-back. Data backup and recovery shall be seamless to the user with management tools for data archival and retrieval.

The HIS content and structure shall be modifiable to meet the changing business requirements. Management tools shall provide access control to information and applications in the HIS.

No data loss shall occur due to heavy loading on the historian's data sources, e.g., all one (1) and four (4) second data items captured without loss.

The HIS shall offer a uniform view of all historical data from the TPSCM solution.

Requirement Schedule:

i.	The Historical Information System shall meet the requirements defined in 3.3.8.
ii.	The Historical Information System shall be initialised with information from current production historian systems for the required historical retention period.
iii.	It shall be possible to create custom user interfaces, scripts and required data quality validation rules on the Historical Information System as is available in the current production historian systems.
iv.	It shall be possible to create customised database tables to store external data that is brought into the Historical Information System and be available to the user interfaces.

3.3.8.1 User Interface

Requirement Schedule:

i.	The webserver for the historians shall be Linux based. Data queries, display, entry and changes shall be intuitive. The trends/information available from the historians shall enable and support performance monitoring and management reporting.
ii.	The interface to model data to be included for the historian shall be consistent across the TPSCM.
iii.	The user interface for the control centres shall be driven from the production HIS.
iv.	Access for user on the *Employer* corporate network shall be limited to the historian in the DMZ.
v.	The switch-over of the user interface shall be seamless between the historian in the PCC and SCC.

3.3.8.2 Replication and redundancy

Requirement Schedule:

i.	The historical information shall be consistent between the production and DMZ historian and between the PCC and SCC.
ii.	It shall be possible to influence the detail design with regards to the priority given to the active view of the historical data from the active site versus a view of the independent active and passive sites.

3.3.8.3 Information Exchange

Requirement Schedule:

i.	All the historians, those on the operational network and DMZ network, shall be updated from the source such as the Energy Management System, Wide Area Monitoring System and the Generation Dispatch System so that the information in the historians are consistent.
ii.	It shall be possible for the historians to interface with the Data Gateways.

3.3.8.4 Archiving

Requirement Schedule:

i.	Online historical measurements shall be stored in a relational database on the HIS for the Energy Management System, Wide Area Monitoring System and the Generation Dispatch System. Archiving shall be from the HIS to an archive server.
ii.	Access to historical archived measurements shall be managed via an appropriate interface manager, which shall allow the flow of information to the real-time database and historians for control centre applications such as Situational Awareness Applications or the Enterprise Historian.
iii.	Local storage and software replication shall be evaluated with the assistance from the storage provider and approval from the supplier prior to the finalisation of the architecture.

4. Authorization

This document has been seen and accepted by:

Name and surname	Designation
Aletta Mashao	Senior Manager Distribution Engineering
Anita Oommen	Manager Operations Performance
Gav Hurford	Senior Manager National Control
Isabel Fick	General Manager System Operator
Julia Zulu	Manager Business Support
Lawrence Padachi	Corporate Specialist Demand Side
Lizzy Busenga	Manager Metering and Data Services
Louis du Plessis	Manager National Operations
Martin Kopa	Manager Operations Planning
Mervin Mottian	Manager Distribution Network Operations and Support
Phokoane Moshodi	Senior Manager Grid Code Management
Prudence Madiba	Senior Manager: Generation Asset Management - C&I COE
Siju Joseph	Manager Ancillary Services
Timothy Zulu	Manager System Operating Control

5. Revisions

Date	Rev	Compiler	Remarks
Dec 2021	1	R. Botha	New document is required that details requirements for a TPSCM system.

6. Development team

The following people were involved in the development of this document:

- System Operator - National Control Systems Support

7. Acknowledgements

Not applicable.