



IMPROVED OPERATIONS AND RELIABILITY BY UPGRADING OLKARIA I CONTROL SYSTEM AND INSTALLING REMOTE MONITORING AND CONTROL SYSTEM FOR OLKARIA I AND II GEOTHERMAL POWER PLANTS IN KENYA

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ABSTRACT

Operational and maintenance aspects of geothermal power plants largely depend on the type and architecture of control systems installed. Design concepts and technical features are important aspects to consider in order for a geothermal power plant to operate with minimum failures and interruptions. A control system integrates all of the plant's individual systems and enables them to cohesively operate as a single system. The main objectives of carrying out a control system upgrade and installing remote monitoring and control is to improve plant reliability and availability, ensure safe operations of the plant, lower the costs of generation, improve plant efficiency, reduce environmental effects and conserve energy. High reliability is the most important feature. Considerable reduction in the life-cycle costs of a geothermal project can be achieved through the careful development and implementation of long-time strategies for the design and commissioning of remote monitoring and control systems and for the upgrades of older control systems. The advantages that can be gained by implementing such systems have led to an improvement in automation and emphasis on monitoring and control away from the plant's central control room. The Olkaria I and Olkaria II power plants in Kenya can indeed be propelled to achieve state-of-the-art automation and the highest level of plant control.

1. INTRODUCTION

Olkaria I and Olkaria II geothermal power plants are located in the Kenyan rift valley about 120 km northwest of the capital, Nairobi. The plants belong to Kenya Electricity Generating Company – KenGen, a limited liability company owned by the government of Kenya (70%) and public shareholders (30%). KenGen supplies 80% of the electricity used in Kenya. It utilizes various sources to generate electricity including hydro, geothermal, thermal and wind. It has a total installed capacity of about 1000 MW, of which 115 MW is geothermal. KenGen sells the power in bulk to Kenya Power and Lighting Company, KPLC, a limited liability company responsible for the transmission, distribution and retail sales of electricity throughout Kenya. KenGen is now operating in a liberalized market and is in direct competition with four Independent Power Producers who between them produce 20% of the country's electric power. KenGen has a workforce of 1,600 staff distributed in 20

different sites in Kenya where its power plants are located. With its wealth of experience, established corporate base and a clear vision, the company intends to maintain leadership in the liberalized electric energy sub-sector in Kenya and in the East Africa region.

Olkaria I power plant has an installed capacity of 45 MW. The plant was commissioned in three phases and has three units, each generating 15 MW of electricity. The first unit was commissioned in June 1981, the second in November 1982 and the third in March 1985. The plant was designed for nominal 25 years but with proper maintenance it will last much longer. Olkaria II power plant has an installed capacity of 70 MW. The plant was commissioned in October and November 2003 and has two units, each generating 35 MW of electricity. Currently, construction of a third unit of 35 MW electricity is underway.

2. THE CONTROL SYSTEMS AT OLKARIA I AND II POWER PLANTS

Plant control and monitoring at Olkaria II is fully automated and computerized (Figure 1) through the distributed control system (DCS) provided by Mitsubishi Heavy Industries (MHI). MHI's plant distributed control system is known as Digital Intelligent Automation System (DIASYS) Netmation. This control system provides high reliability, economy, advanced automation and easy maintenance. DIASYS Netmation is based on the latest in communications and information technology and provides a centralized management scheme to help ensure efficient plant operations.



FIGURE 1: The control room of Olkaria II power plant (Mwangi, 2006)

Features of the DIASYS Netmation;

- High reliability;
- Advanced control functionality;
- Human engineering-based superior operability;
- Easy maintenance.

Olkaria I, being an older plant, does not have computerized controls but operates on an analog control system (Figure 2). It uses the Proportional Integral Derivative (PID) controllers that have the following characteristics:



FIGURE 2: The control room of Olkaria I power plant

- Continuous process control;
- Analog inputs/outputs;
- Set point (SP);
- Proportional (P), Integral (I), and / or Derivative (D) constants.

2.1 Plant operators

At Olkaria I power plant, the plant operators work throughout the installation as well as in the central control room. They monitor the process by checking the meters, recorders, instruments and

switchboards to make sure that all systems are working efficiently, safely, economically and within established limits, and in many instances control equipment manually. They watch and listen to machinery and routinely check safety devices, identifying and correcting any trouble that develops.

Olkaria II power plant is manned by plant operators who work mainly in the central control room. Each plant has its own plant operator staff. Plant operators work in 8-hour shifts and on a rotating basis, each shift has four (4) attendants drawn from various job levels such as superintendent, technician, foreman, craftsman, artisan or turbine operator. Shift assignments change periodically, so all operators can share duty on less desirable shifts. Work on rotating shifts can be stressful and fatiguing, because of the constant change in living and sleeping patterns. The tasks of the plant operator can include the following:

- Start up, operation and shut down of the steam turbine-generator units and auxiliary equipments. This is done in accordance with the operating instructions and procedures. The engineers are always called upon during unplanned shutdowns and also they assist with the start up.
- Synchronize generators to the grid and regulate load, voltage and frequency.
- Take readings in given time intervals and compile reports on equipment performance, instrument readings, switching operations and loads on generators.
- Analyze the condition of the equipment to detect flaws or defects in operation and take appropriate steps to correct defects or hazardous conditions.
- Perform emergency operations to maintain electric service and safeguard station equipment (human intervention).
- Perform switching operations from the control room to allow for isolation, as required by the maintenance teams. This is done accurately and safely in accordance with established procedures.
- Monitor the status of all safety systems such as fire protection.
- Keep manual records of unusual incidents, malfunctioning equipment or maintenance performed during each shift in the occurrences book. This book is readily available upon request to any staff that needs the information. (Maintenance teams use the *Management Maintenance System* (MMS) software in scheduling and reporting on routine maintenance).
- Respond to alarms by taking appropriate corrective action.
- Carry out turbine valve stem-freedom tests, turbine protective device tests, emergency pump and auxiliary oil pump auto-start tests, diesel generator tests.

2.2 The need for remote monitoring and control

Olkaria I and II power plants require remote monitoring and control for decision-makers and maintenance personnel to be able to perform monitoring and diagnosis from home or from the headquarters in Nairobi.

2.2.1 Browser operator station (OPS)

By installing and setting up browser OPS software on a browser resident personal computer, one can obtain the same functionality as provided in the central control room. Operation and monitoring can be performed by simply connecting to the internet using the same browser OPS as in the central control room. By connecting to the operator's intranet via the internet or a leased line, plant operation and monitoring, and diagnosis are possible from home or office. One way of carrying out such remote monitoring and control is by using a secure microwave link and a dedicated phone line.

2.2.2 Mobile on-site monitoring

An alternative solution can be realized via:

- i. *Wireless local area network (LAN)* making it possible for OPS functionality to be realized on-site using a tabletop personal computer (PC). This offers plant monitoring and control throughout the entire power plant. Since all functions are available using just a web browser, a business PC or similar computer can be used effectively without modification (Figure 3).
- ii. *Global system for mobile communications (GSM)* based solutions whereby the critical alarms are registered and delivered in real time via e-mail to the mobile.

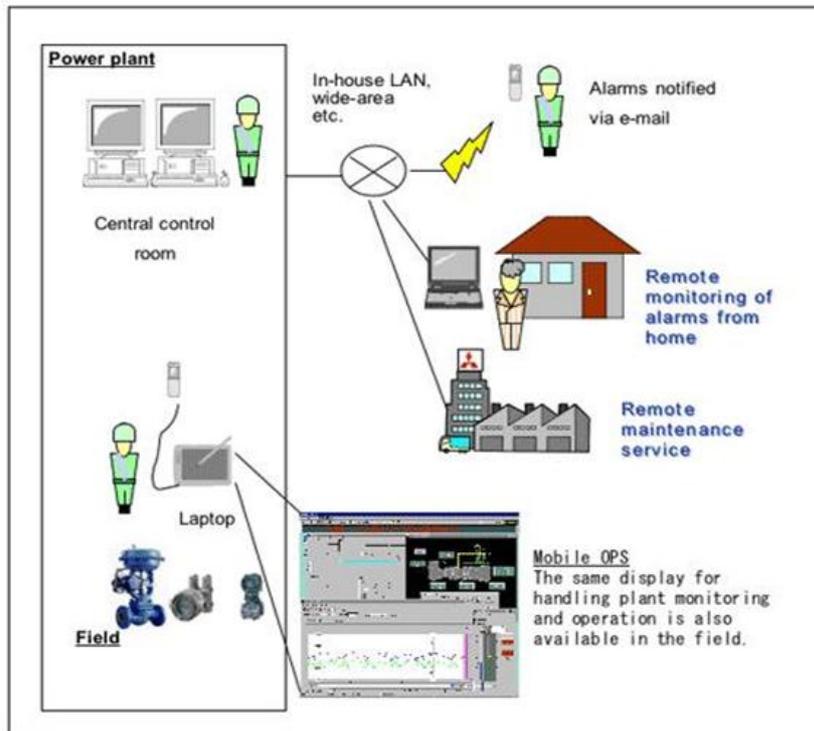


FIGURE 3: Remote monitoring and mobile on-site monitoring (MHI, 2002)

Lack of these functions makes it difficult for the maintenance personnel to know immediately if a problem occurs in the plant and to take quick, proper action. During the night, week-end or on holidays, plant operators report emergency plant breakdown and major anomalies in plant status to the engineer on standby duty, through mobile or landline telephones. The engineers, who live at least 15km away from the power plants, respond to calls by travelling to the plant. From the central control room they check the series of events, trends and alarm trace that preceded the anomaly. This method prolongs the outage period, and makes it difficult to improve system-wide

performance or decrease maintenance costs. Remote monitoring from home is necessary so that the engineers can issue appropriate instructions to the operators from home without having to waste time travelling to the plant.

Plant operators keep the engineers and decision makers informed of plant performance by sending daily generation data reports using the computer. Most recipients of this data are at the head office, about 120 km from the power plants. They depend on these reports for information on the plants' performance. Lack of remote monitoring prevents them from collecting real time feedback information on the operations of their equipment and implementing proactive planning and maintenance strategies.

2.3 Future plans for rehabilitation/redevelopment of Olkaria 1 power plant

KenGen is currently undertaking an optimization study that entails a cost benefit analysis for the rehabilitation/redevelopment of Olkaria 1 power plant. The study will determine the current condition of the Olkaria I power generation plant, recommend the best method for utilizing the geothermal resources available at this location, worthwhile overhauls capable of increasing operating efficiency, and prolonging the useful life of the plant and steam gathering and reinjection systems. It will also determine where and how best to access and utilize the available steam reserves through the installation of a new Olkaria IV power plant and, if justified, the implementation of the improvements of Olkaria I. In the latter case, upgrading of the control system is inevitable.

3. HARDWARE ARCHITECTURE

3.1 Olkaria II control system

DIASYS Netmation is the Mitsubishi Heavy Industries' control system (MHI, 2006a) in use at the Olkaria II plant (Figure 4). It is a network integrated system, including user friendly human-machine interface, where the components interface each other via the network. A description of the system components is given in the following subsections.

3.1.1 Multiple process station (MPS)

The MPS controls the plant automatically, and handles the plant's inputs and outputs. It executes control logic and performs complex arithmetic processing that requires high-performance processing such as turbine governor control, as well as automatic plant start/stop control. The system is configured to connect to a ModBus via ControlNet. The features of MPS include:

- Central processor unit (CPU), Celeron/Intel processor;
- Redundant system configuration with duplicated CPU, power supply, network;
- Plug-in silicon (pSOS) operating system;
- Compact peripheral component interconnect (PCI) bus;
- Flex I/O modules (Figure 5), plug-and-play structure;
- Max. 64 flex I/O modules, (four rows of eight modules on each front and rear of cabinet);
- Control net, open network for programmable logic controllers (PLC);
- Self-diagnostic functions and indication features.

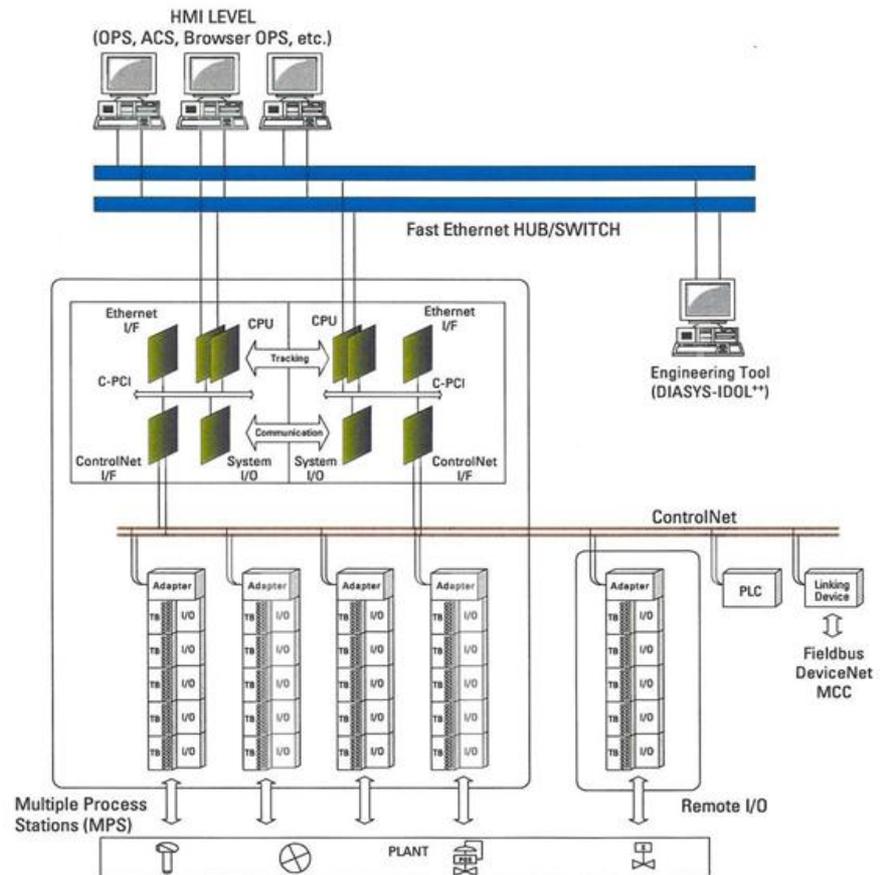


FIGURE 4: System configuration for Diasys Netmation control system at Olkaria II power plant

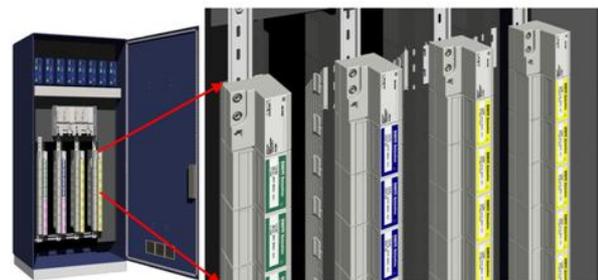


FIGURE 5: Input/output modules

3.1.2 Operator station (OPS)

The *Operator station* (OPS) is a user-machine interface that is used to monitor and operate the plant. Features of OPS include:

- Background screen has optional settings that can be customized such as an alarm format, a display format, push button arrangement.
- Security level can register all operations. It can be used by different users, each with a certain security level. All operations are stored as history in the ACS and can be displayed.
- Display information such as numerical value, symbol and list can be linked to each other as follows:
 - From alarm message to alarm logic;
 - From symbol such as lamp and numerical value to logic, etc.
- By drag-and-drop action a tag number, trend signal, etc. can be registered from a numerical value. It is therefore, not necessary to search for a tag number/name from the list and keyboard.
- Tagging is available for items independently. For example, valves whose operation is prohibited by some users maintain the tagged status until all the users cancel the stop-tagging.

3.1.3 Engineering and maintenance station (EMS)

The *Engineering and maintenance station* is used to maintain the whole DCS by using DIASYS-IDOL⁺⁺ software. It provides the ability to perform a variety of operations, ranging from modification and creation of control logic, design of graphic displays, trends and control loop plates, all the way up to and including configuring an entire system. Features of the EMS include:

- Drag & drop interface (VISIO based tool);
- Windows PC based system;
- Fully integrated tool for design, monitoring and tuning the control diagram.

3.1.4 Accessory station (ACS)

The ACS is a system equipped with a powerful relational database for storing and managing large amounts of plant data. Removable media such as magneto-optical drives for data storage can be easily connected. It also acts as a web server for interfacing with other web servers and external devices.

Functions of ACS include:

- *Storage*: makes a collection of reports, event/alarm trace and middle-term/long-term data.
- *Trip log collection*: collects and saves the processed data before and after a trip.
- *Maintenance log*: displays the elapsed operation time and the total number of starts and stops of specified auxiliary plant equipment.
- *Operator action log*: records important operator actions such as control loop plate operations, manual settings, parameter adjustments, and login to the OPS as an event.
- *Printer management*: manages the printer used by all functions of ACS and performs backup.

3.1.5 Automatic voltage regulator (AVR)

The excitation system at Olkaria II plant is self-excitation (DC rotating generator and brushless exciter). The *Digital automatic voltage regulator* (D-AVR) system is located in the excitation control panel which is interfaced with the DCS MPS through the digital input/output cards. The D-AVR has a dual redundant configuration [AVR (A) and AVR (B)] as in Figure 6. The Var/Power factor control is integrated into the D-AVR system. The D-AVR system provides the following standard functions that are essential for generator control:

- *Sequential control*: Normal starting and stopping of excitation system
- *Automatic voltage regulator (AVR)*: Adjusts the generator terminal voltage constant so that it agrees with the reference.
- *Under excitation limiter (UEL)*: Prevents the AVR from reducing generator excitation to so low a value that the generator would fall out of synchronism.

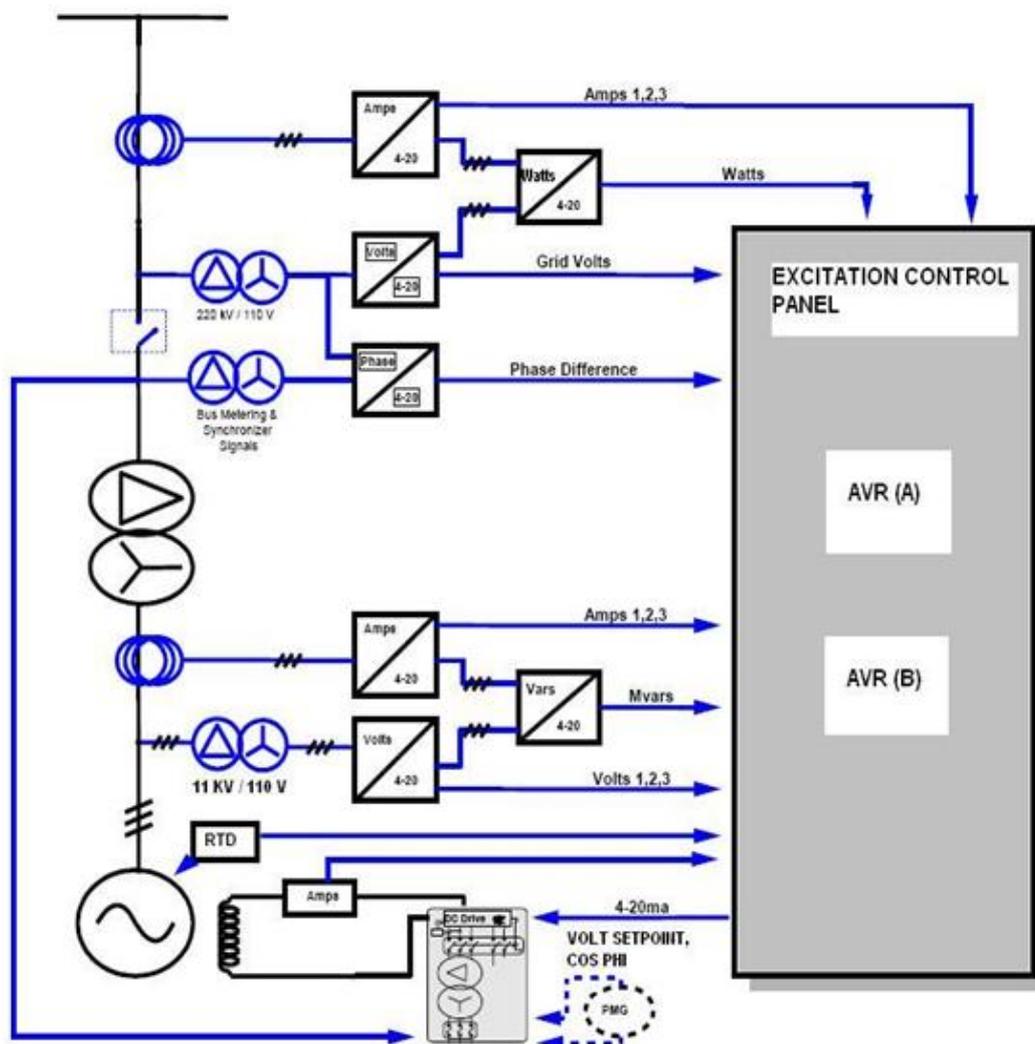


FIGURE 6: Automatic voltage regulator (AVR)

- *V/F limiter*: Prevents the generator from over-flux condition by monitoring the ratio voltage/frequency.
- *Over excitation limiter (OEL)*: Prevents the AVR from increasing generator excitation to a value so high and for a time so long that the generator rotor thermal capability would be exceeded.
- *Over excitation protector (OEP)*: Protects the generator from field over current beyond OEL limiting.
- *Power system stabilizer (PSS)*: Improves the damping of electric-mechanical resonance mode between the generator and tie-line. It provides supplemental control signal to AVR by detecting instantaneous deviation of generator output power (Delta P) or frequency (Delta f).
- *Automatic follow-up of voltage reference (AFU)*: Makes voltage reference of the standby channel following that of the working channel.
- *Manual excitation controller (MEC)*: Maintains the field current constant so that it agrees with the current reference. It is standard that the MEC is exclusively used for commissioning tests.
- *Reactive current compensator (RCC)*: Reduces the reactive current among generators paralleled on the same bus by supplying a compensation signal corresponding to the reactive current of each generator to the reference.
- *84V*: The generator voltage detecting function for voltage build-up sequence.
- *60AVR*: The voltage difference detecting function between two VTs for sensing VT circuit failure.

- *Transient response recording (post mortem review)*: Records the transient response signals for tests, or data before and after an accident.

3.1.6 Turbine governor

The turbine governor at the Olkaria II plant is a *Digital-electro-hydraulic* (DEH) type. The controls are centralized in the DEH cubicle that is integrated to the DCS MPS through the ControlNet. The DEH cubicle (Figure 7) contains the CPU, Ethernet interface card, ControlNet interface card, system input/output card and analog/digital input/output modules. Examples of modules are: over speed protection module, turbine electric over speed trip (EOST) module and turbine interlock logic module. DEH system inputs/outputs include:

- Synchronization circuit breaker “52G ON” digital input;
- “Auto stop oil pressure low” input;
- Turbine interlock output (main stop valves (MSV) all close, governor valves (GV) all close);
- “Overspeed protection controller (OPC) solenoid value” output;
- 1~12000 rpm speed input;
- Rectified speed pulse output;
- 4~20 mA analog input / 1~5 V analog output;
- Generator “MW” output.

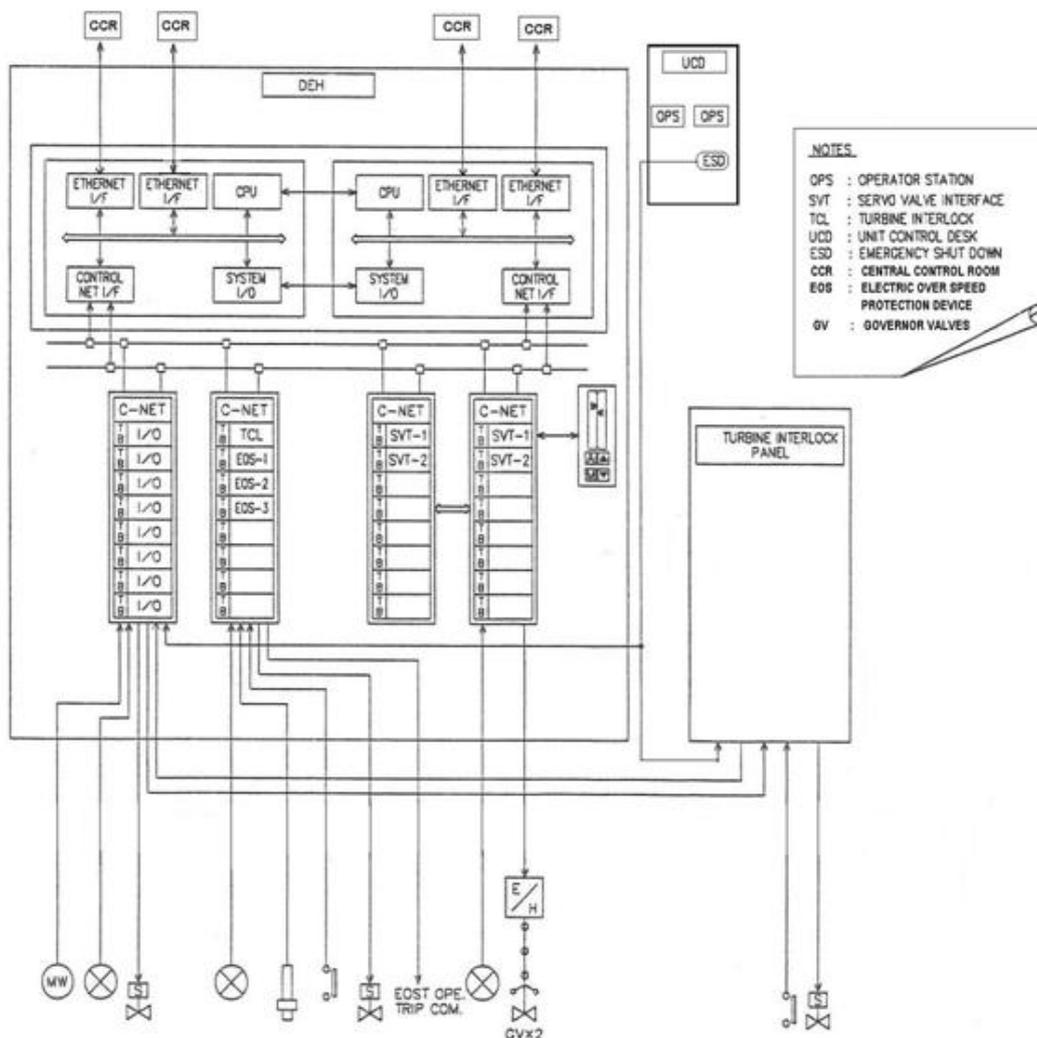


FIGURE 7: The Digital-electro-hydraulic (DEH) system at Olkaria II power plant

Control functions of the DEH system include:

- *Turbine control*: Remote reset or shutdown of the turbine, opening or closing the main stop valves (MSV) by commands to the electro-hydraulic valves.
- *Speed control* (by frequency signal): Converts a frequency signal to a corresponding turbine speed value, compares the speed to target speed and regulates the opening of turbine valves.
- *Power output control*: Regulates the turbine loading.

3.1.7 Protective relays

Olkaria II power plant has modern, multifunction, digital protection relays offering a high degree of protection. The relaying and protection system is integrated into the DCS MPS via digital input/output cards, and time synchronized from a GPS system. The generator and transformer protection relays are housed in the generator-transformer protection panel while other types of relays are in the switchgear room. Advantages of multifunction relays include:

- With multiple protective functions built into a single relay, there is a considerable cost and maintenance advantage, a reduction in installation space and wiring requirements.
- Programmable protective functions, programmed alarm and trip pick-up points can easily be configured using a laptop PC through a RS-232C serial port.
- Wide range of protection, monitoring, control and recording functions in one compact unit.
- Metering and displaying of measured currents, voltages, watts, vars, PF, Hertz, VA and Wh.
- Better diagnostics with sequence of events, fault display, time-synchronization and fault reports.
- Greater reliability due to faster relay trips and alarm response, better fault detection and no thermal drift.

SR 745 Transformer management relay

The SR 745 Transformer management relay (Figure 8) is a high-speed, multiprocessor based relay for the protection and management of power transformers. It has an embedded 10BaseT Ethernet capability that provides faster data transfer, thus improving system performance. It has protection functions such as percent differential (87T), negative sequence time overcurrent (51/46T), ground time overcurrent (51G-T) and more.



FIGURE 8: SR 745 transformer management relay



FIGURE 9: SR 489 generator management relay

SR 489 Generator management relay

The SR 489 Generator management relay (Figure 9) has an embedded Ethernet communication port located on the back panel of the relay that allows it to be connected directly to the Ethernet bus, using Modbus TCP/IP protocol (GE, 2001). It has protection functions such as generator differential protection (87G), generator volts/hertz or overexcitation (24G), generator stator ground fault (64G) and more.

3.1.8 Vibration monitoring

Vibration analysis is one of the most important condition monitoring techniques. It involves real time data acquisition and analysis. The aim of vibration monitoring is to detect defects by analysing changes in the vibration condition of the equipment during operation. Vibration analysis is normally

applied by using transducers to measure acceleration, velocity or displacement. The choice largely depends on the frequencies being analysed as follows (Asok et al., 2002):

- 0 up to 200 Hz (measures displacement using proximity probe)
- 2 Hz to 2 kHz (measures velocity using velocity transducer)
- 0 up to and beyond 20 kHz (measures acceleration using accelerometer)

Turbine/generator vibration monitoring

The signals from turbine / generator sensors (probes, accelerometers, velocity transducers) (Figure 10) are forwarded to the turbine supervisory panel, which is integrated to the DCS MPS via digital input/output cards. The vibration information is trended over time and analyzed to detect anomalies.

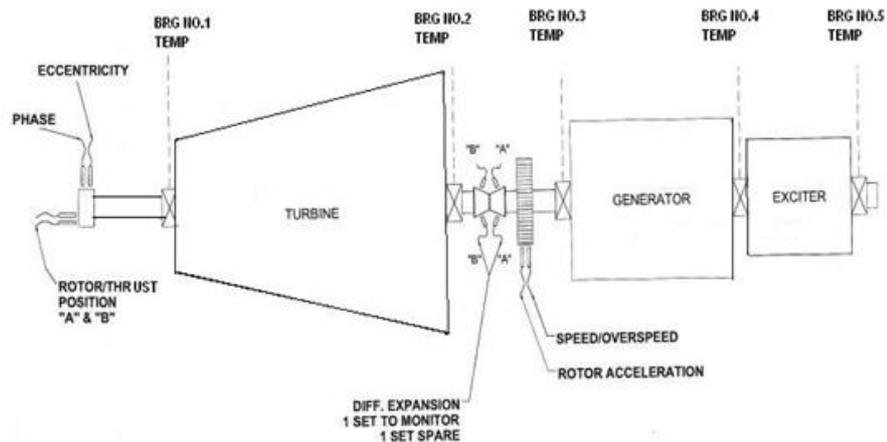


FIGURE 10: Vibration monitoring for the turbine-generator system (Rockwell, 2006)

Some of the parameters monitored are:

- Speed* measures the shaft rotation in revolutions per minute. It is a critical measurement during start-up for accurately matching the synchronous frequency before synchronizing the generator to the power grid.
- Acceleration* measures how fast speed is increasing or decreasing. It is monitored during turbine roll-up so that a steady increase in machine speed is achieved.
- Eccentricity* measures the amount of sag or bow in a rotor.
- Differential expansion (DE)* is the difference between the thermal growth of the rotor compared to the thermal growth of the case, most critical during a turbine "cold" start-up.
- Overspeed* measures the machine's acceleration beyond its maximum permissible rotational speed.
- Temperature* measures how hot a bearing is operating.

Cooling tower fans vibration monitoring

Vibration monitoring is also carried out on pumps, motors, fans and compressors. For example, the 1900/55 fan monitor (Figure 11) is used to measure casing vibration velocity on the cooling tower fan gear boxes. It uses the 190501 Velomitor transducer that is suitable for low-frequency applications. The transducer gives a response of 1.5 to 1000 Hz ± 3 dB, corresponding to fan speeds of 90 rpm or greater. The monitor has a communication card allowing it to send real-time information to the DCS MPS.

3.1.9 Motor control centres (MCC)

The motor starters at the Olkaria II power plant are of the conventional type, with thermal overload relays. They are housed within the motor control centres (Figure 12). The controls for the starters are connected to the DCS MPS through the digital input/output cards. For example, to start motor (A) the CPU will cause a relay driver on a digital-output card to latch a relay closed. This relay will close a motor starter that causes motor (A) to start.

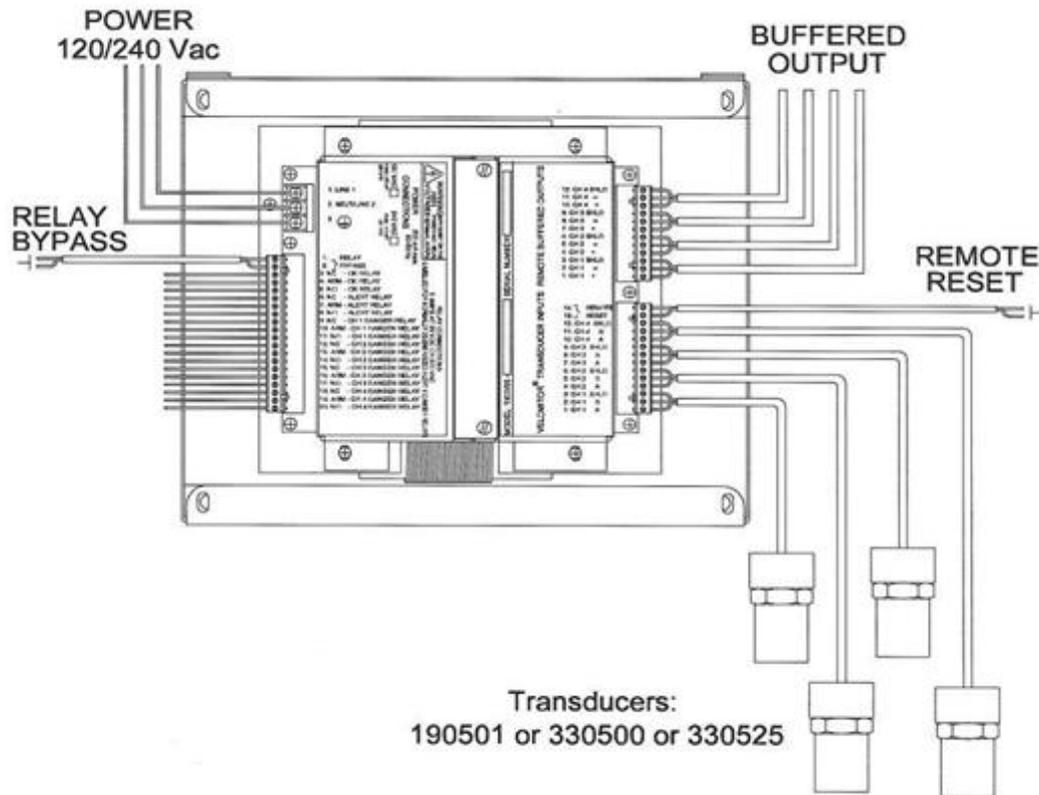


FIGURE 11: 1900/55 fan monitor and 190501 Velomitor transducers

The SIMOCODE pro is the new motor management system for low-voltage motors. The system is the intelligent link between the automation system and the motor feeder. SIMOCODE pro implements all motor protection and control functions, and provides operational, diagnostic and statistical data.

3.1.10 Communication buses

- *Ethernet*: The unit network is a closed 100 Mbs, industry standard Ethernet bus that unites the system components.
- *ControlNet*: The network protocol for DCS that interfaces the I/O cards (by Allen Bradley) to the CPU. I/O card expansion is provided by adding I/O cards to ControlNet. Similarly, function modules such as turbine interlock cards are also connected to ControlNet.
- *Modbus* is used to connect the DCS to the steamfield controls (Figure 13). The MVI94-MCM communication module is used to interface Modbus master and slave devices with the I/O system (Rotork, 2000). The module is fitted to the actuator on the Rotork valves in the steamfield. The module performs the tasks of RS485 interface, actuator data collection and the issuing of actuator commands.



FIGURE 12: Motor control centres (MCC) at Olkaria II power plant

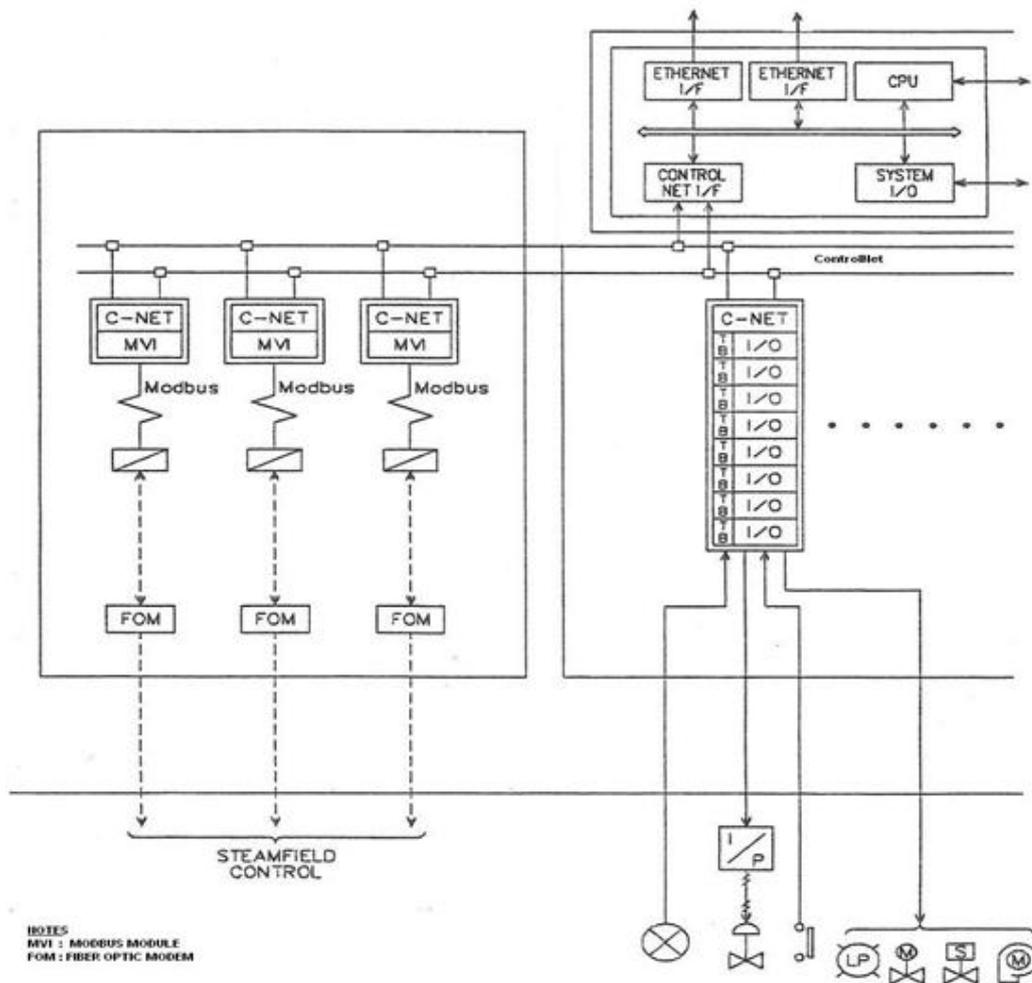


FIGURE 13: DCS interface to steamfield control

3.2 Olkaria I control system

The Olkaria I control system is analog, built by Mitsubishi Heavy Industries (MHI). The C640 controller (Figure 14) with process indication (deviation indication) receives as an input the converted value 1-5 V DC of a process variable, changed into a standard signal of 4-20 mA by the transmitter. The deviation between this signal and the set point is subjected to proportional, reset and rate operations to give an output of 1-5 V DC or 4-20 mA DC.

The PID controller calculation (algorithm) involves three separate parameters: the proportional, the integral and derivative values (Figure 15). The Proportional value determines the reaction to the current error, the Integral determines the reaction based on the sum of recent errors and the Derivative determines the reaction to the rate at which the error has been changing. The weighed sum of these three actions is used to adjust the process via a control element such as the position of a control valve (Liptak, 1995).

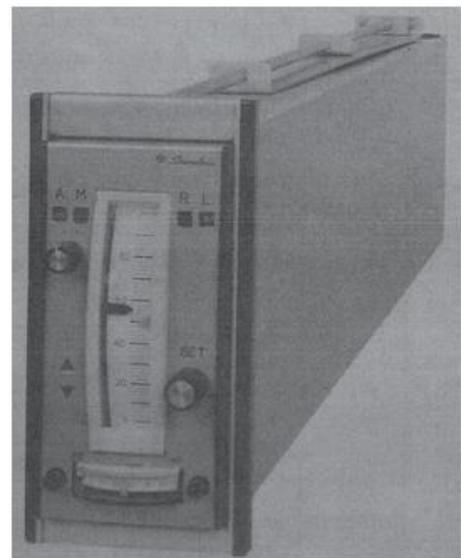


FIGURE 14: Type C640 controller at Olkaria I power plant

3.2.1 Proportional integral derivative (PID) controllers

The following are some illustrations of how PID controllers operate:

a) *Temperature controllers:*

Temperature for a fluid in a vessel/pipe is expressed as an analog signal. The temperature sensor is an RTD or thermocouple, the temperature transducer scales the temperature value to some defined form/units and then feeds that value to the controller. The controller then controls a valve or pump on a cooling or heating line to maintain the temperature.

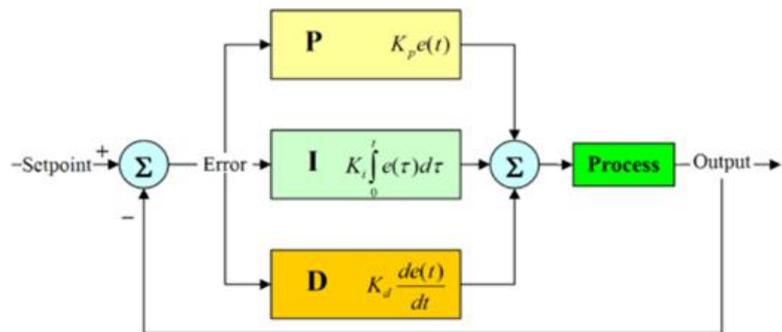


FIGURE 15: Proportional-integral-derivative (PID) controller (Wikipedia, 2008)

b) *Pressure controllers:* Pressure in the pipe is expressed as an analog signal. The pressure sensor measures the pressure (bars, Pascals, psi), the transducer scales the pressure to some form/units and then feeds that value to the controller. Based on the value and the set point, the controller controls a valve or pump to maintain pressure (HTS, 2005).

3.2.2 Protective relays

Olkaria I plant has ninety electro-mechanical protection relays for three machines; each relay performs a single function.

3.2.3 Turbine governor

Olkaria I plant operates on an electro-mechanical turbine governor.

3.2.4 Analog signals for instruments and control

The signal levels are conventional (Table 1), so the control system upgrade should be easy in that respect. A transducer converts a measurement from one form to another, for example, a condenser level with a scale range 0-1000 mm is converted into a current signal of 4-20 mA, vibration with a scale range 0-0.4 mm is converted into a voltage signal of 2.5-40 mV, turbine speed with a scale range 0-3000 rpm is converted into a current signal of 0-5 mA.

3.2.5 The control room

The control room houses the switchboard, generator/turbine board, excitation unit and governor unit. Some of the components on the boards are:

- Meters (Amps/Volts/Vars/kilowatts);
- Synchronization switches, start/stop switches;
- Indicators for speed, vibration, pressure, load, vacuum, level;
- Vibrations, steam pressure/temperature, turbine speed and valve position recorders;
- Integrator, turbine supervisory instrument;
- Computing and protective relays;
- Controllers for pressure, level, and flow.

TABLE 1: Instruments/devices in Olkaria I control system and their corresponding analog values

Item no.	Instrument/device name	Range of values
1	Vibration recorder	2.5 - 40 mV
2	Turbine speed and valve position recorder	0 - 5 mA
3	Steam pressure recorder	4 - 20mA
4	Indicators for speed, generator load, vibration	0 - 5 mA
5	Indicators for pressure, vacuum, level	4 - 20 mA
6	Integrator	4 - 20 mA
7	Controllers for pressure, level, flow (manual station)	4 - 20 mA
8	Computing relay	4 - 20 mA
9	Turbine supervisory instrument – vibration control	2.5 - 40 mV
10	Turbine supervisory instrument – speed, position control	0 - 5 mA
11	Flow transmitters	4 - 20 mA
12	Pressure transmitters (local)	4 - 20 mA
13	Level transmitters (local)	4 - 20 mA
14	Electro-pneumatic converter	4 - 20 mA
15	Power supply for control system	AC/DC 110 V

4. SOFTWARE

4.1 Olkaria II software

Olkaria I plant does not operate on any software as the controls are not computerized, but at Olkaria II, the DIASYS Netmation system uses the DIASYS-IDOL⁺⁺ software from MHI. DIASYS-IDOL⁺⁺ software provides a conventional control logic description language based on IEC 61131 - compliant function block diagrams. It has elements for performing data execution, control and monitoring of the operator station and IEC-compliant function blocks, making it possible to configure an entire system (MHI, 2002). DIASYS-IDOL⁺⁺ is installed on a Windows NT-based PC.

4.1.1 Features

The DIASYS system has the following features:

- Uses conventional MHI's control logic description language;
- Is based on Microsoft Windows PC;
- Function elements for maintenance of DCS:
 - OPS display build up;
 - Control logic design;
 - System configuration;
 - Drawing management (Excel, Word, AutoCAD).
- Unified database is used to configure the DCS (object database) designed to manage all the components used for control logic or those displayed on operator stations. This setup eliminates duplicate efforts by centralizing the management of all data in one location.

At the core of DIASYS-IDOL⁺⁺ is a database used to configure the DCS, called the object relation control architecture (ORCA). ORCA is a database designed to manage all the components used for control logic or displayed on operator stations. This setup eliminates duplicate efforts by centralizing the management of all data in one location. Control logic and efficiency calculation formulas can easily be created using VISIO, a drawing tool renowned for its user friendliness. Users can create and modify configurations and relationships simply by dragging and dropping prepared elements,

eliminating the need for programming knowledge. DIASYS-IDOL⁺⁺ is used to manage all the information in the ORCA core database. In ORCA, each information item is always managed as a component (object).

4.1.2 Functions

The functions are prepared for each design task and then all share data in the Object Database.

- *Logic data creation function: **Logic window***
This function allows one to create logic data (Figure 16) that is processed by the MPS. Logic window manages logic data. To change logic or create new logic, a VISIO-based tool called LogicCreator (FLIPPER) is used.

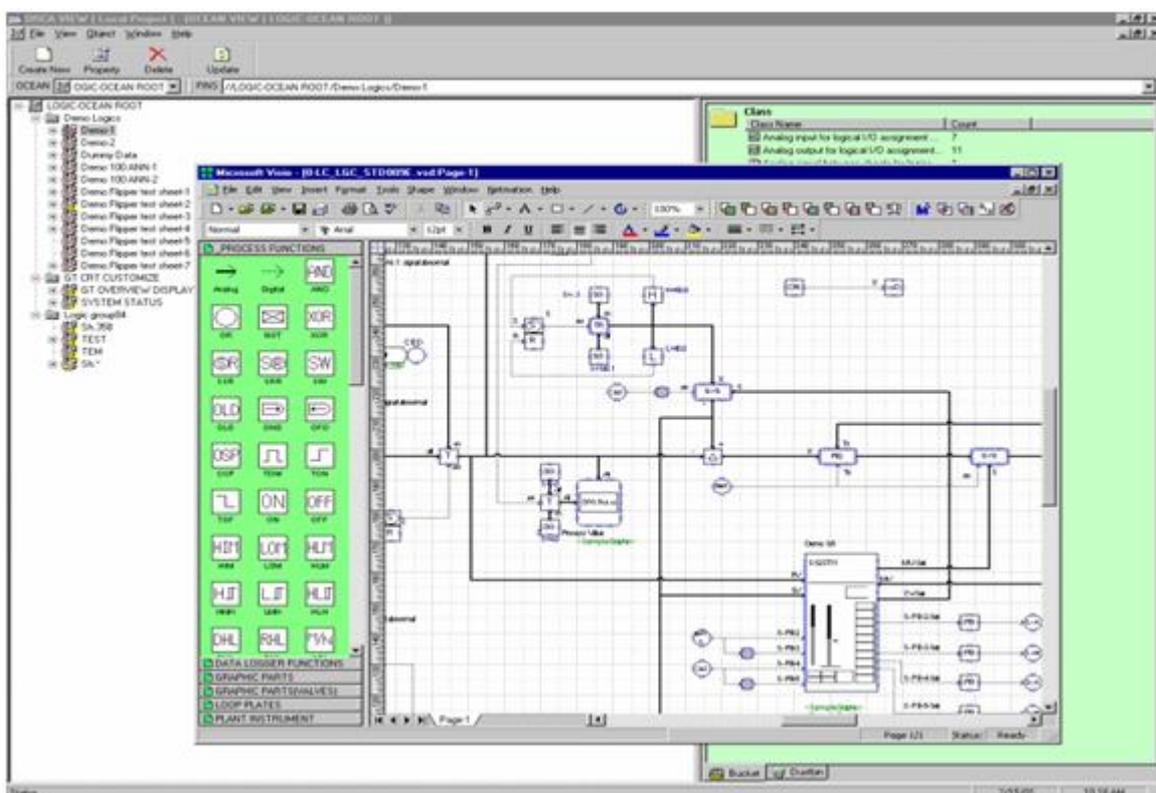


FIGURE 16: Sample logic creation screen

- *Graphic creation function: **Graphic window***
This function allows one to create graphics (system diagrams) displayed on the OPS. Graphic window manages graphic data. To change a graphic or create a new graphic, a tool called GraphicCreator (MARLIN) is used.
- *System building function: **System window***
This function allows one to specify the overall definitions of the system. One can specify the components connected to the unit network (MPS, OPS, and ACS), manage the information about each component (regarding communications and others), and set the module configuration in the MPS (such as signal assignment for I/O modules).
- *User-machine interface between the OPS and the ACS: **HMI window***
This function is used to set the functions and windows to be used and displayed on each OPS and ACS. This window is also used to manage control loop plates. However, to change the

definitions of control loop plates or create a new control loop plate, the LoopPlateCreator (SCALLOP) is used.

- *ObjectDatabase (ORCA) creation and change function: Document window*
Other functions of the EMS can also be used to create and change ObjectDatabase (ORCA). In document window, Excel is used to create and change the database efficiently. Document window manages files in Excel format. To edit an Excel file, the ListCreator (CORAL) is used.
- *Document management function: Drawing window*
This function is used to collect the data created using other functions of the EMS, and change it into electronic files for management. The drawing window is used to convert the logic sheets created using LogicCreator (FLIPPER), the graphics created using GraphicCreator (MARLIN) and the Excel list documents created using ListCreator (CORAL) into PDF format for management.

4.2 The MPS central processing unit (CPU)

The control logic software program rests in the *MPS central processing unit* (Figure 17). The MPS CPU acts on the instructions received from the OPS. Acting on the message may be a very complex procedure, it may require checking the required position, sending an electrical signal to a field device that orders it to change states, checking a set of switches to ensure that the order was obeyed and sending back a message to the OPS to confirm that the new condition has been reached. Main features of the CPU:

- Type: Compact PCI CPU card (Celeron/ Pentium);
- 133 Mbps Compact PCI Bus;
- Intel / Celeron CPU with 300 MHz clock;
- 32 kbytes primary cache / 128 kbytes secondary cache;
- 1 channel Ethernet I/F.



FIGURE 17: CPCPU01 Compact PCI CPU card

4.3 Creating a human-machine interface (HMI) application

A graphic diagram that is displayed on the OPS can be created using *InTouch 10.0 HMI Software*, e.g. cooling tower graphic diagram (Figure 18).

Steps:

1. Launching ArchestrA IDE and creating a new window;
2. Building the window by embedding ArchestrA graphics;
3. Connecting to data: Creating access name, configuring an I/O server and defining tags;
4. Animating the objects: Linking the Tagnames to the components' symbols;
5. Running the application by clicking runtime icon on the toolbar (top right).

Defining tags:

Tags are defined (Table 2) using the Tagname dictionary. A tag represents a data item. Tags are created for those process components whose properties are to be monitored or controlled with the application, e.g. a pump has properties such as pressure, RPM and status whose values are associated with tags in the HMI.

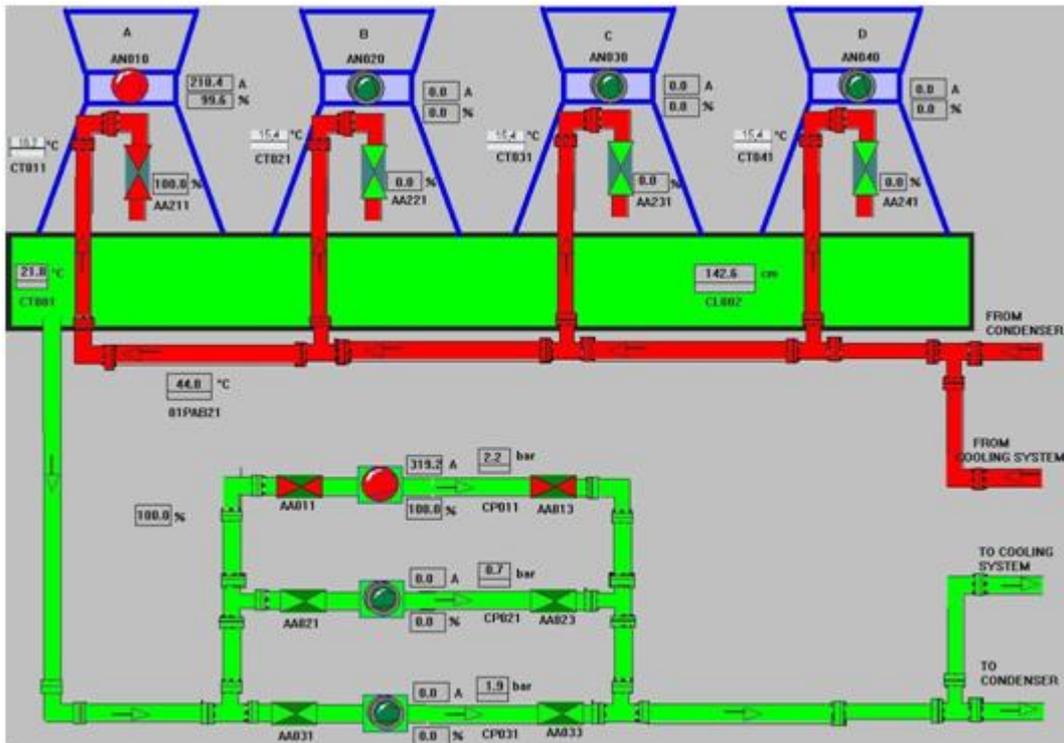


FIGURE 18: Cooling tower graphic diagram

Tag types:

When a tag is defined, it is assigned to a specific type according to the intended purpose of the tag or the type of data that is associated with it. Application's tags can be assigned to four different types based upon the process data associated with the tag, that is, integer, real, discrete or message data, e.g. the PumpState tag returns a Boolean on/off value to indicate if the pump is running or stopped. The tagname dictionary includes data types for memory, I/O and indirect tags.

- Discrete tags are associated with process component properties whose values are represented by two possible Boolean states;
- Integer tags can be assigned 32-bit signed-integer numbers;
- Real tags can be assigned floating decimal point numbers;
- Message tags can be assigned text strings up to a maximum of 131 single-byte characters.

System tags are identified by a dollar sign (\$) as the first character of a tag's name. The values associated with a system tag can be read-only, write-only or read/write.

TABLE 2: Definition of some tag names used in a cooling tower graphic diagram

Tag name	Tag type	Access name	Alarm group	Comment
Mot_Amp1A	I/O integer	SLC500	\$system	Current reading for fan motor no. 1A
Fan1A_on	Memory discrete	SLC500	\$system	Indication of a running fan
Valv_psn1A	Indirect analog		\$system	Valve opening position
CT_Level	Memory real		\$system	Water level in the cooling tower basin
Press_wat	I/O real		\$system	Pressure of water from cooling tower to condenser
Pump1A_on	I/O discrete		\$system	Indication of running pump

An indirect tag is a tag that can act on behalf of another tag (pointer). Using indirect tags, applications can be created with window objects that show values from multiple tags. Using indirect tags reduces the application development time. Instead of creating a separate set of tags and window objects for each process component, applications can be created with window objects that show values from multiple tag sources.

5. INSTRUMENTATION

The connections between the MPS and instruments are via electrical conductors, but using fibreoptics cable is also becoming popular. Copper wire is normally used; it is shielded to prevent electromagnetic interference or noise from corrupting the signal and armoured to give some physical protection. If unarmoured, the cable is fed through rigid pipes (conduits) or laid in protective channels (cable tray). The cable is then encapsulated in a jacket of fluid-proof, flexible plastic to protect it from moisture, corrosive atmospheres and toxic and flammable fluids.

5.1 Instrument control using analog signals

This is a control using continuous values, effective via analog input/output cards. For example, to open a valve to a 60% position, an analog signal is usually developed to represent the valve position (Figure 19). When the valve opens fully, the transmitter output will be +5 volts and when the valve is fully closed, the output will be 0 volts. Very often a signal range of 4-20 mA is used, +5V then corresponds to 20 mA, and 0 V corresponds to 4 mA. For a 60% valve position the transmitter output is +3 V, which is then converted to 13.6 mA. Instead of going directly to a register, the 13.6 mA signal is sent to an analog-to-digital converter that is inside the analog input card (Figure 20) that changes it into a series of binary digits and stores these bits in a register.

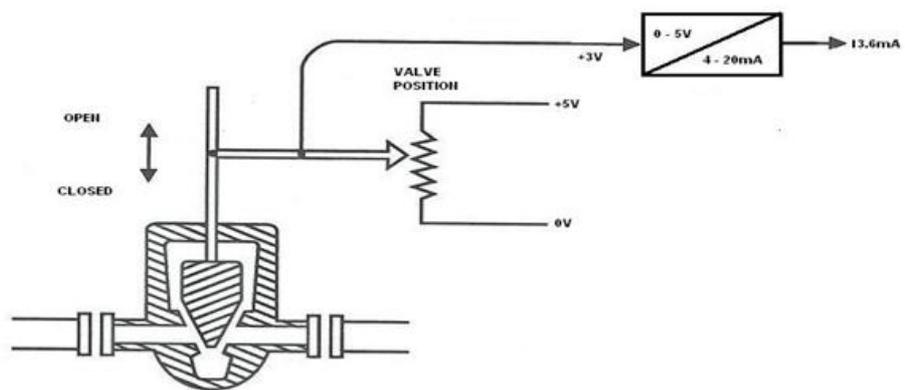


FIGURE 19: Valve position represented as an analog signal

Very often a signal range of 4-20 mA is used, +5V then corresponds to 20 mA, and 0 V corresponds to 4 mA. For a 60% valve position the transmitter output is +3 V, which is then converted to 13.6 mA. Instead of going directly to a register, the 13.6 mA signal is sent to an analog-to-digital converter that is inside the analog input card (Figure 20) that changes it into a series of binary digits and stores these bits in a register.

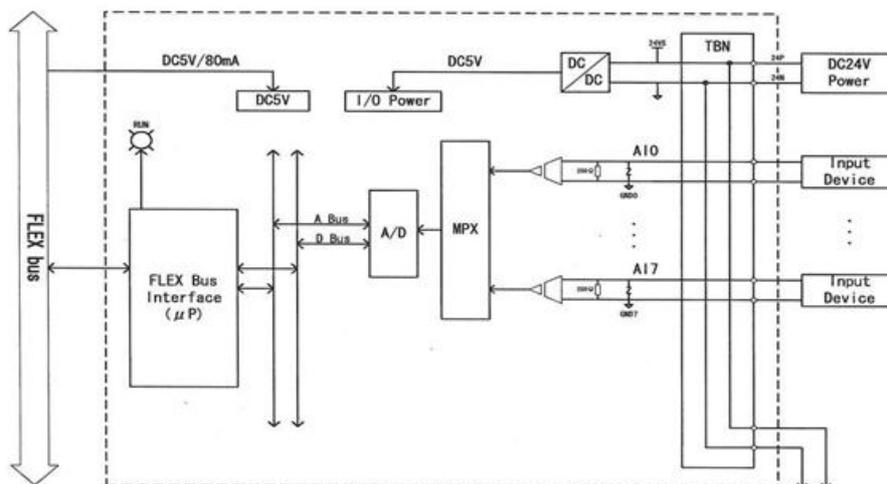


FIGURE 20: Analog input module FXAIM01 block diagram

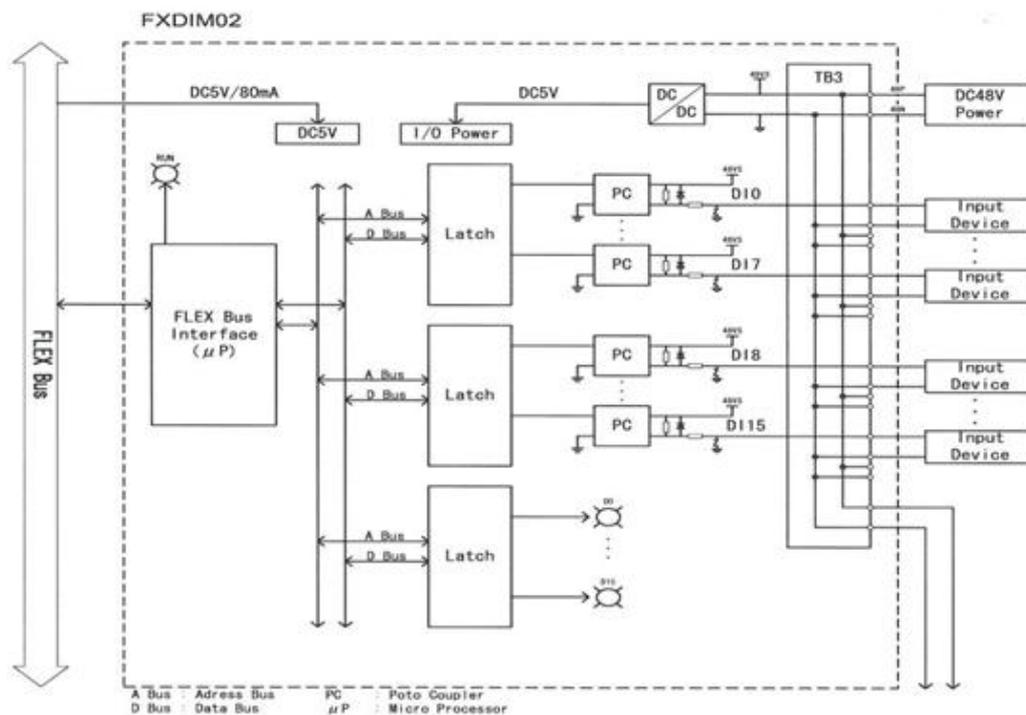


FIGURE 21: FXDIM02 digital input module block diagram

5.2 Instrument control using digital signals

This type of control uses discrete values "0" or "1", effective via digital input/output cards. The instrument (sensors) receives information from the process and converts it to a form that is usable by the control system, which then feeds a digital input card (Figure 21). Pneumatic-powered or electric-powered actuators supply force and motion to instruments such as valves.

5.3 Modern instruments that support control systems

The following are examples of some modern instruments used in the Olkaria II control system:

- DVC6000 series Fieldvue valve positioner*: This is a digital valve controller (Figure 22) communicating, microprocessor-based current-to-pneumatic instrument. In addition to the traditional function of converting a current signal to a valve-position pressure signal, the controllers use HART-communications protocol. Using this protocol, diverse (various) valve information can be integrated into a control system.
- 144LD Intelligent buoyancy transmitter*: This transmitter (Figure 23) performs measurements for liquid level, interface or density of liquids. The measurement is based on the Archimedes buoyancy principle. Easy remote configuration and supervision can be done with a PC or universal hand terminal. The device can also be operated conventionally using the local keys.
- Model 3095 MV™ Multivariable™ mass flow transmitter*: This is a transmitter (Figure 24) that provides cost-effective mass flow measurements for steam, gas or liquids. This compact device accurately measures differential pressure (DP), static pressure and process temperature to dynamically calculate fully compensated mass flow. It simultaneously measures all process variables necessary for calculating either pressure and temperature compensated gas flow, or



FIGURE 22: DVC6000 series Fieldvue valve positioner



FIGURE 23: 144LD Intelligent buoyancy transmitter



FIGURE 24: Model 3095 MV™ Multivariable™ mass flow transmitter

temperature compensated liquid flow and provides a 4-20 mA signal proportional to mass flow for control or metering purposes.

6. CONTROL SYSTEM UPGRADE

As a power plant ages, maintenance tends to increase and breakdowns become more frequent. This is also true for instrument and control systems. One of the most cost-effective solutions for improving the reliability, availability and operation of older electric power generation plants is to upgrade and modernize a plant's instruments and controls. Control modernization programs are designed to improve the operation, life and maintenance of the plant.

It is a myth that software does not age. Software ages quickly if it is not upgraded. The functions can only be guaranteed if the software is administered and updated regularly. If software is not regularly upgraded there is a risk that service for the control system is no longer available. The engineering tools, manufacturer support and the service staff available will no longer be willing or able to service the control system using the old software. This could lead to prolonged unavailability of the plant in case of control system failure. It may therefore often turn out that the constant (often meaning annual or semi-annual) updating of the control system software is most economical. This is called keeping the system "evergreen" and is sometimes a requirement in a control system supplier maintenance contract. The reason is that the service work can be performed more efficiently if only the most recent software versions have to be dealt with.

6.1 The life-cycle of a control system

The life-cycle of the control system is often shorter than that of the plant itself. For a geothermal power plant with a lifetime longer than say 30 years, it may be expected that the control system will be renovated at least once during the life of the plant. If frequent modifications are being made to the control system, due to evolution of the geothermal project, then the need for renovation of the control system will be more frequent. Several factors influence the need for control system renewal, one of them being the costs involved. The life-cycle cost of the control system is dependent on the initial purchase price of the plant control system.

One aspect to consider is that the automation level (plant control system, programmable logic controllers) is much more stable (automation functions are seldom changed significantly) than the operator station (OPS). This is because the information technology (IT) that the operator station is based on is subject to much shorter product cycles than the automation level. Every effort must therefore be made to make the frequent operator level upgrades as economical as possible, especially regarding the work intensive interface with the automation level (programmable logic controllers). Standardisation of the communication between the automation and operator level is very important in this respect. Effective migration strategies and tools for upgrading the operator level are another important aspect. A highly developed migration strategy for upgrades is a competitive edge that control system manufacturers with a strong market position often have (Magnússon, 2003).

6.2 The need for a control system upgrade at Olkaria I

Older plants are often operating with many individual analog systems, each requiring custom support and training. Often data acquisition is limited to a few measurements. The insufficient alarm function increases the time needed for failure diagnosis and repair. The need for excessive maintenance and many components becoming obsolete are the main factors influencing the decision for an upgrade. The failure rate of the old control system hardware increases, affecting plant reliability.

The system upgrade involves building a digital system (Figure 25) from an analog system (Figure 26), making it possible to realize the full benefit (meaning high reliability and high operability) of modern plant control. It is important to plan and invest in a control system upgrade for the following benefits:

- A digital control system saves hours of time in troubleshooting, resulting in shorter fault detection and elimination times. This leads to a more economic system and high plant reliability.
- Improved response time to changes initiated by the operator or by occurrences in the field.
- Digital control system presents process data in real-time, providing the operators with instant visual operating data, easy-to-read alarms and trip information, thus enabling the operators to operate the plant more efficiently.
- Digital control systems being computer based provide the operators with a full spectrum of information that is used for trending and diagnostic analysis. This information is used for detecting problems at an early stage, thus reducing costly shutdown of the plant and improving plant availability.
- Improved operator interface to the plant through the use of operator station (OPS), accessory station (ACS), and large visual screens (LVS).
- Improved accessibility of plant data to engineering and management staff.



FIGURE 25: Digital control room



FIGURE 26: Analog control room

- Historical storage and retrieval systems of plant data, logs and reports.
- Easy maintenance of the control logic, graphic displays through the use of engineering maintenance station (EMS).
- A digital control system pays back its cost many times over.

6.3 Planning for geothermal power plant control system upgrade

All upgrades of control systems should start with strategic planning, to ensure that the life-cycle cost of the plant is kept to a minimum and operational goals are met. Strategic planning starts with a thorough evaluation of the existing control system together with a review of operational experience, and then follows a study of the available options and their benefits versus drawbacks. Several benefits result from developing and implementing an overall strategy for the design and implementation of a new control system:

- Savings are realized by selecting a standard digital platform. This usually means deciding on a control system from one or a few manufacturers. This reduces training and spare parts costs.
- Standardised human-system interface (HSI). The HSI is the key to operators' situational awareness and proper response to plant malfunctions. The use of many different types and often badly conceived HSI is one of the main sources of human factor deficiencies and operator mistakes in power plant operation.

In some instances, power plant modernizations are begun on an individual equipment or system basis, replacing the most problematic parts without consideration of an integrated, long-term view of the resulting plant control system architecture. Whether the modernization covers the whole plant at once or is implemented in several phases, strategic planning is needed as one of the initial steps in the modernization project. The lack of strategic planning can result in:

- Older control system components being unable to communicate with current/future systems.
- Control system components may become prematurely obsolete due to lack of support or incompatibility with future control system additions.

6.3.1 Problems associated with control-system upgrades

When implementing a digital control system, consideration must be given to the potential for software common-mode failures. Redundant, software based components are especially vulnerable to common-mode failures during software upgrades that can introduce the same failure to both parts of a redundant system. When planning an upgrade, due consideration must be given to this.

6.3.2 Human-system interface modernisation plan and design

Planning for the impact of a control system upgrade on the human-system interface is crucial. Power plant and control system modifications and upgrades are often piecemeal efforts implemented over a long time and without a firm plan for a resulting well integrated and harmonized HSI. Each modification is designed on its own, often using different vendor equipment resulting in inconsistent human-system interface characteristics. History has shown that incoherent HSI modifications have been a significant source of human factor related hazards in power plants. In addition, maintaining many types of HSI can become costly.

When upgrading a control system and designing a new HSI, one of the first steps should be to check if the old, existing graphical HSI can be used as a basis for tools and base picture elements in the new HSI. Then the basic picture elements needed to create the process displays should be defined in detail. The dynamic behaviour of the picture elements and dialogues also need to be defined. The design of displays is often an iterative process between the HSI specialists and the customer. It should be

emphasized that the customer should be involved in the design of picture elements and other display conventions. This is to ensure that the design conforms to the existing plant HSI conventions and thus limits the amount of operator re-training required.

6.3.3 Naming conventions for systems, equipment and signals

When planning for major upgrades of a power plant, the opportunity is sometimes used to make a change in the naming system. To ensure that the naming conventions are applied consistently, it is preferable that only one person or a group of persons should assign names for new signals and objects. It is important to make sure that the naming system is completely defined and well understood by those assigning new names, before starting to use the new names.

6.3.4 Participation by plant staff

The participation of plant staff in upgrade work has several advantages. They bring to the project extensive knowledge of the existing plant and its operation. Direct participation in the upgrade project is perhaps the best form of training and education for operations and maintenance personnel. Part of the project's success usually is the involvement of the staff from the beginning. The problem is that often the staff has to perform all the normal duties in addition to the project work. This leads to conflicts with other tasks and potential for delays or undesired technical solutions. The staff should therefore be relieved of most or all of their normal duties and preferably be assigned to the upgrade project on a full-time basis.

7. REMOTE MONITORING AND CONTROL

In recent years, remote monitoring and control in geothermal projects are being used to an increasing degree worldwide. Closed circuit TV (CCTV) is becoming popular for remote monitoring of the surroundings of a geothermal plant. A careful consideration of all factors affecting plant availability is needed when planning for remote control. Remote control and monitoring of geothermal plants are quite often easy and relatively safe compared to other power plants such as fossil fuel thermal power plants. Remote monitoring and control is intended to achieve increased efficiency of operation and maintenance while maintaining reliability and safety.

7.1 The need for remote monitoring and control at Olkaria geothermal power plants

The Olkaria power plants are located in Hells Gate National Park and it is, therefore, not possible for the staff to reside near the power plant. The remote monitoring system would make it possible to monitor and operate the plant process from a remote site. In a case of abnormal plant conditions during the night, week-ends or on holidays, the maintenance personnel immediately go to the power station for troubleshooting upon receiving information on the abnormality from the operators. There is need for remote monitoring and control from remote locations (Figure 27), which are more conveniently located, perhaps several tens of kilometres away from the geothermal plant site (the head office in Nairobi and the housing facility at Naivasha). The decision to monitor and control the plants remotely does have a significant effect on the plants' control systems. In some cases, remote monitoring can facilitate the diagnosis of a failure and thus reduce the time needed for repair.

7.2 Communication interface specification for a remote monitoring system

With remote monitoring we can achieve standard OPS functions with an ordinary PC (laptop) just by connecting to the plant control network. Remote monitoring can be used not only as a monitoring tool

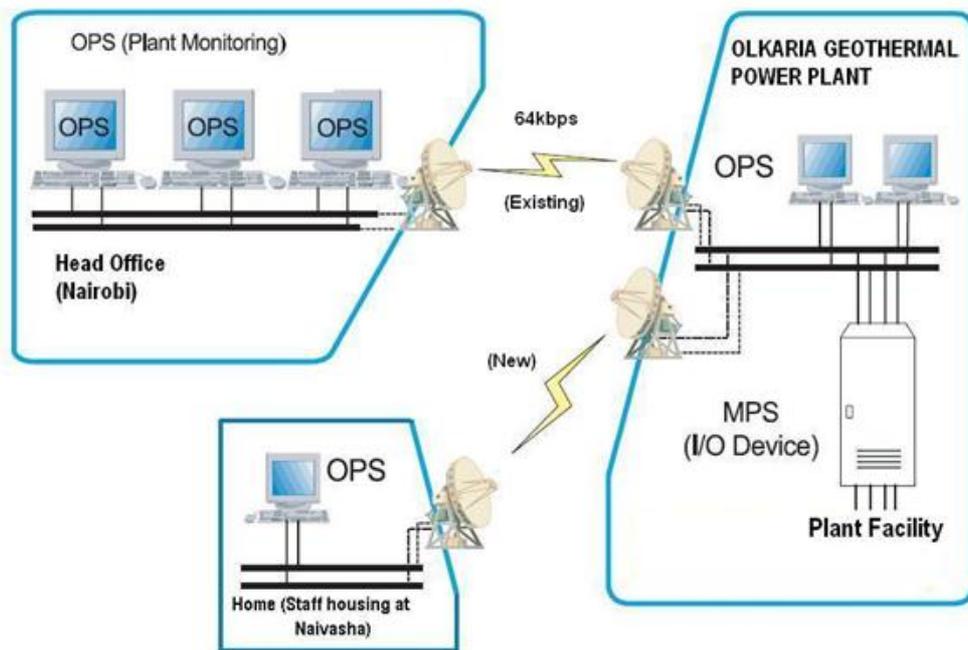


FIGURE 27: Layout of remote monitoring using microwave link communication

but also an operation tool. It is easy to realize remote maintenance from home or head office, since connecting to the plant network can be through the microwave communication link (Figure 28). Scope of supply includes:

- 1) Remote monitoring server PC at the power plant;
- 2) Individual monitoring PCs (laptops) at home or head office;
- 3) Microwave link.

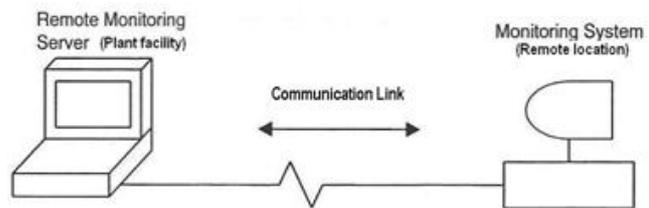


FIGURE 28: Method of connection for remote monitoring

7.3 Low-traffic communication technology and remote monitoring and control

A remote monitoring and operation system allows operations and monitoring at a place far from the plant and a field mobile system enables operations in the field outside the control room. Such systems can be created using a protocol for low traffic (Figure 29) to enable communications between the system components. The traditional control systems periodically send all the process data collected by the controller to user-machine interface devices such as OPSs. Therefore, the larger the plant, the larger the traffic becomes. The low-traffic communication technology queries the controller for the data to be displayed on the OPS, and compresses and sends or receives only the required data.

With the low-traffic communication technology, the traffic required for normal operations and monitoring can be 32 kbps or less per OPS. Therefore, a remote monitoring and operation system can be created using existing low-load infrastructures such as telephone lines and microwaves. You do not need to lay new optical fibres to create a remote monitoring and operation system. Data is not missed even if an unstable communications network might experience momentary lapses of data since the MPS CPU logs and stores data. When communications are restored, the OPS calls the MPS CPU for

data again. Therefore, trend data and alarms are not lost. Other functional degeneration does not occur, either.

7.4 Remote monitoring a standard feature

Extensibility: The same level of monitoring and control can be provided remotely as in a facility's central control room via the internet, microwave circuits, telephone lines or other existing channels.

Mobility: With wireless networks, mobile OPS can be set up using tabletop or notebook PCs to perform the same kind of monitoring and control throughout a facility as in the central control room.

Real-time reporting: The system can be configured to transmit critical alarm messages by e-mail or SMS to a mobile phone so that if a problem arises, the person in charge is alerted immediately, and response can be rapid (Figure 30).

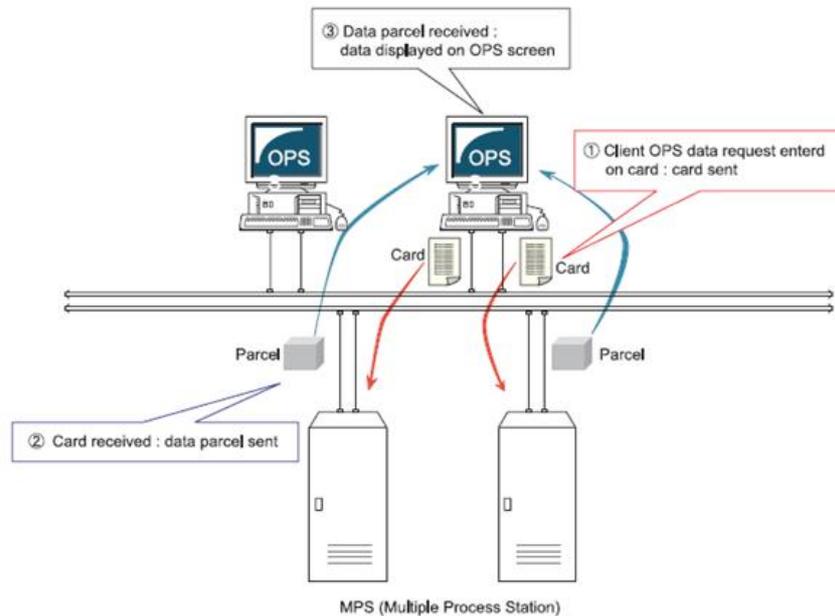


FIGURE 29: MHI card communication

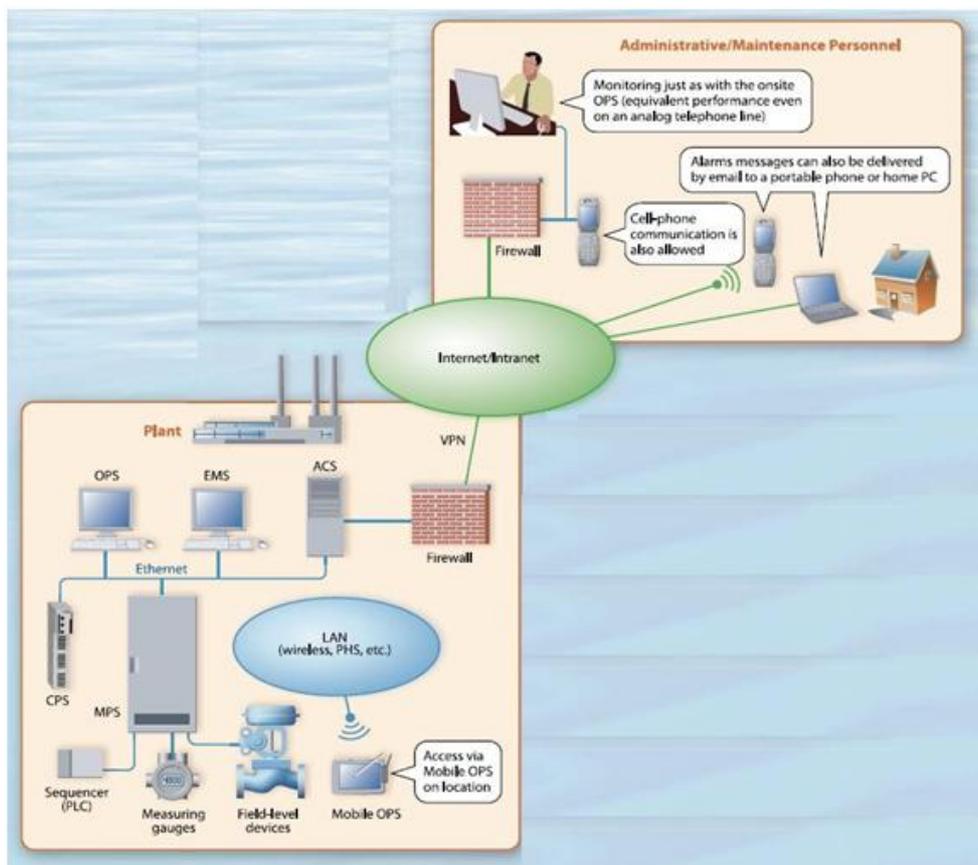


FIGURE 30: Remote monitoring and control system

Excellent operability: All remote monitoring and control are standard with DIASYS Netmation, and need only be activated by the user. Requested data, even if travelling on telephone lines, reaches remote screens at virtually the same speed as data transferred within a central control room.

7.5 Remote monitoring and the hierarchical structuring of the control system

In geothermal power plants, the control system is often split into five different levels (internet, office LAN, plant control/monitoring, control and field levels). The level division (Figure 31) is primarily intended to increase the reliability of the control system (MHI, 2004).

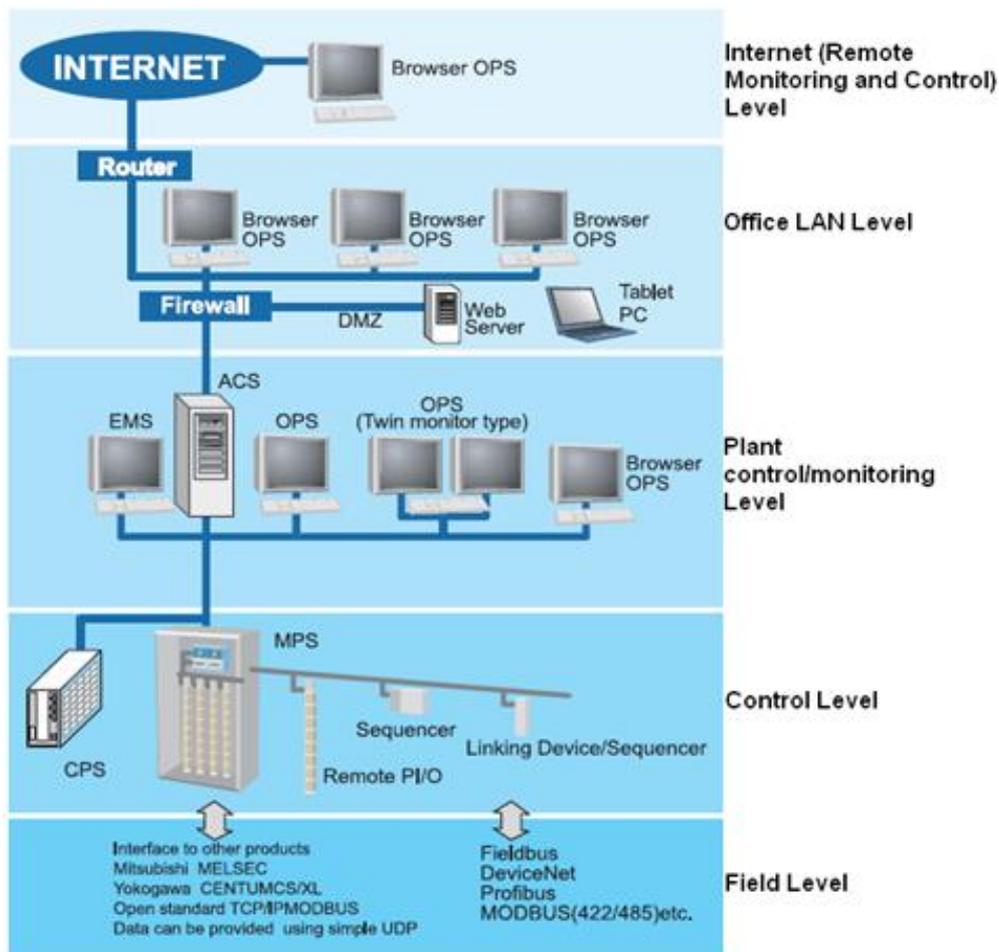


FIGURE 31: Control system hierarchy

- 1) *Internet (remote monitoring) level:* On the Internet level, DIASYS Netmation provides an environment for remote operation and monitoring from home or a distant location. Operation and monitoring are possible by simply connecting a browser OPS to the Internet. This access is password protected.
- 2) *Office LAN level:* On the office LAN level, DIASYS Netmation enables plant operation, monitoring, control, and adjustments via a LAN that connects the entire power plant. Ordinary PCs can be used as browser OPSs without modification. What is more, by simply installing an in-house wireless LAN or personal handy-phone system (PHS) line, mobile OPSs are available and they can be used to monitor plant operation in the field.
- 3) *Plant control/monitoring level:* Connected over a duplex 100 Mbps Ethernet network, the unit level is designed with emphasis on reliability. This level offers an interface to upper layers and

provides the ability to operate and monitor all units. The accessory station (ACS) can store a large quantity of data, provides an interface with upper levels, and controls printers and other peripheral devices. The operator station (OPS) is placed in the central control room and efficiently provides the operator with a variety of displays and methods of operation. The engineering maintenance system (EMS) is used to configure the entire system and create logic operations for controlling the system.

- 4) *Control level:* On the control level, devices are connected using the ControlNet. This level enables high-speed input/output processing and provides the ability to seamlessly configure control systems. Moreover, since it supports duplex systems and optical fibres, wide-area plant monitoring and control systems can be configured. The MPS and compact processor station (CPS) can be connected to DCS and PLCs of other manufacturers via Ethernet or ControlNet (which is the input/output network). The MPS can also be used to perform arithmetic calculations and control the system, as well as collect short-term (hourly) data.
- 5) *Field level:* This level provides ports to external networks such as a fieldbus (ModBus in the case of Olkaria II) by connecting linking devices to the ControlNet network. Remote, batch maintenance of terminal field devices can also be performed.

7.6 Control system redundancy

Manual control is often difficult or cannot be applied for operation in case the main control system fails. A standby or redundancy control system of key system components (Figure 32) is therefore

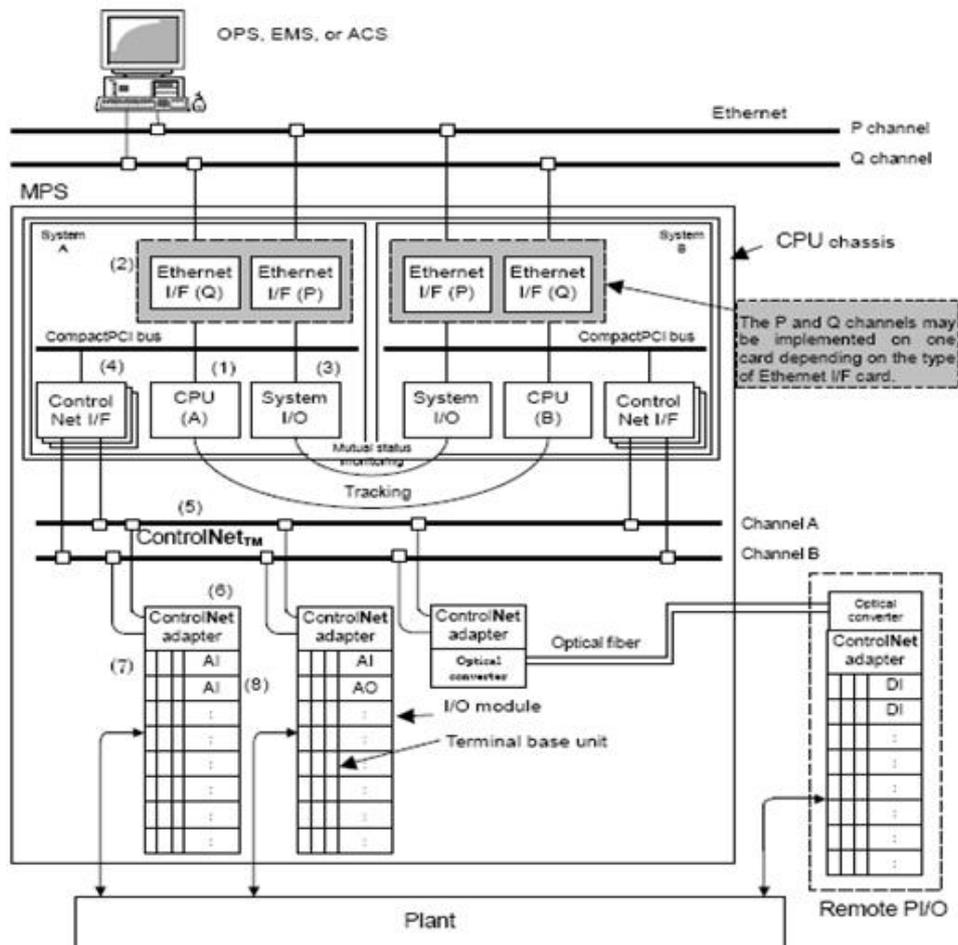


FIGURE 32: System configuration of a multiple process station

important for reliable and uninterrupted operation of the plant. In geothermal power plants, control equipment for the steam and heat exchanger subsystem cannot be controlled manually as they are too fast. A redundant, automatic control system is therefore necessary.

The standby component starts automatically when the running component fails. The control system for Olkaria II plant is configured such that the power supply (Figure 33), MPS CPU, Ethernet interface module, system I/O module and ControlNet interface module take into account redundancy.

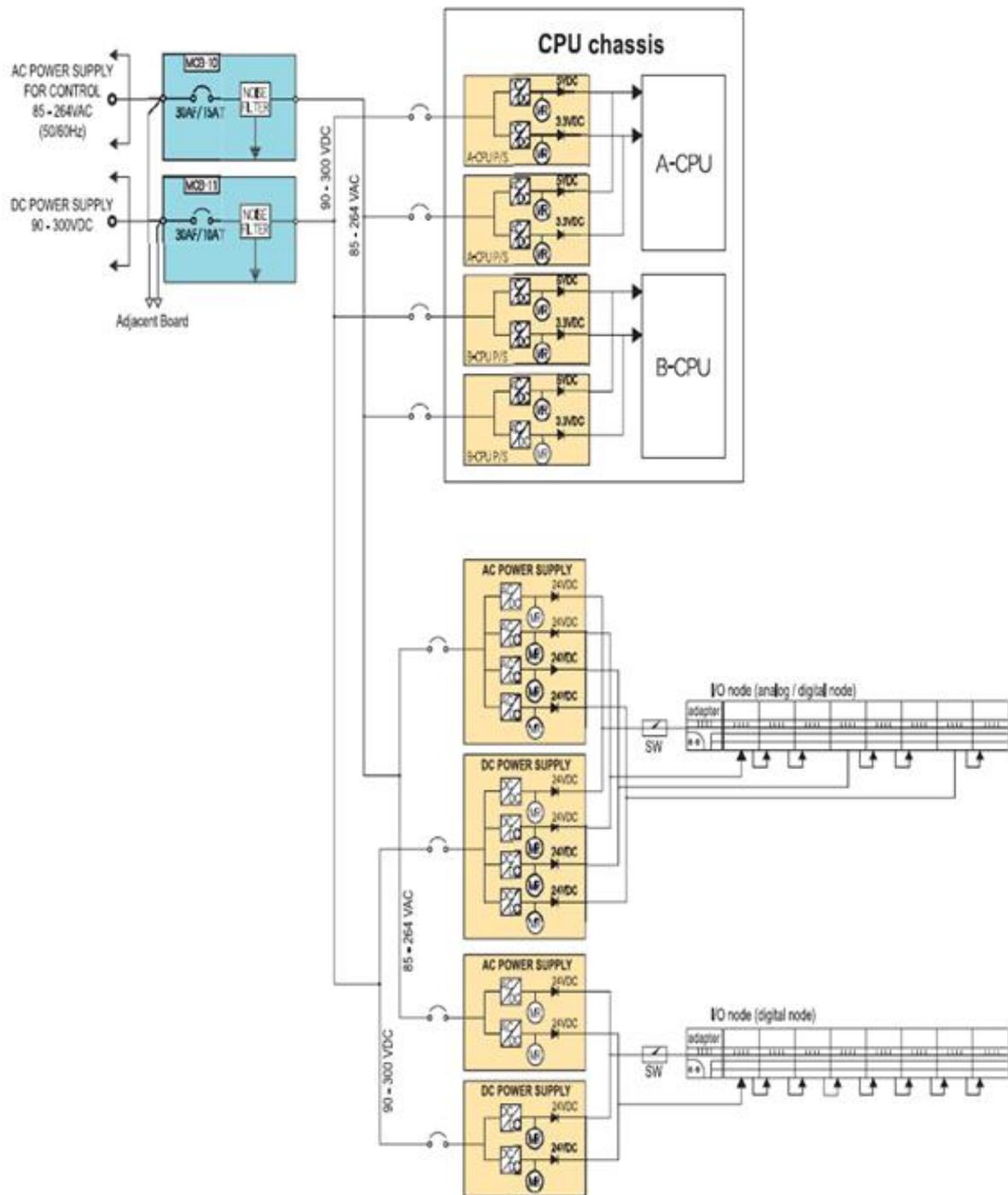


FIGURE 33: Control system power supply system (MHI, 2006b)

8. HYDROGEN SULPHIDE CORROSION AND CONTROL SYSTEMS

Most of the Olkaria I plant process is controlled through control relays and manual or automatic switches and electromechanical protective relays whose moving contacts are made of either copper or silver. All the unprotected copper and silver and their respective alloys are already contaminated. Operational and maintenance costs have been relatively high due to direct effects of H₂S corrosion on the geothermal turbine/generator auxiliaries. The non-condensable gases are usually composed of 99.5% carbon dioxide gas, 0.4% Hydrogen sulphide gas and 0.1% other gases (methane, hydrogen, nitrogen, and carbon monoxide). The H₂S corrosion has caused contacts' burning and destruction of 415 V, 3.3 kV and 11 kV circuit breakers, malfunctions of control circuits, equipment protection devices and air conditioning units.

It is important to note that the highest H₂S level recorded at Olkaria is 4.40 ppm, which was at the power plant. The occupational exposure limit (O.E.L) of H₂S in work places is 10 ppm for an average 8-hour day (Kubo, 2003).

8.1 Design considerations during construction of Olkaria I power plant

In an effort to prevent H₂S gas effects on electrical equipments, the following was considered, designed and constructed at Olkaria I power plant (Mitsubishi Electric Corporation, 1981):

- The protection relays, auxiliary logic relays and most of the magnetic contactors and control switches are located inside the central control room and in the switchgear rooms.
- The central control room and switchgear rooms are positively pressurized with clean, H₂S filtered air. Air from the outside is passed through activated-charcoal air-filters to two air conditioning plants before entering the central control room and the switchgear rooms.
- The central control room has a duplicated door at its main entrance to segregate its clean air from the contaminated outside atmosphere.
- The generators are totally enclosed and pressurized with clean H₂S filtered air. The make-up cooling air is usually passed through activated-charcoal air-filters.
- All the electrical control panels' doors are fitted with airtight rubber seals.
- All the electrical, electronic and instrumentation devices installed outside the air-conditioned rooms are fully enclosed in boxes that have rubber sealed covers and tightly fitted plastic cable conduits.

8.2 Reasons for corrosion on the electrical switchgears and control systems

Despite the efforts taken during the design and construction of Olkaria I power plant, most of the devices are already affected by H₂S gas. The following have been noted as the most probable causes (Mutua, 2002):

- All the electrical contacts and cabling are made of either copper or copper alloy or silver.
- The air-conditioning units' frequent breakdowns allow contaminated atmospheric air to enter the central control room and the switchgear rooms.
- The rubber air-seals on the control panels usually become brittle and broken.
- The non-condensable gases are injected into the atmosphere via chimneys only two meters above the power house roof.
- The tin-plating for the electrical copper wires is too thin.
- The use of activated charcoal in the air-conditioning units is inefficient.
- Outdoor electrical/electronic cabinets are without cleaned air supply.

8.3 Problems expected as a result of H₂S corrosion on electrical control circuits

- 1) *Loss of control signal:* Due to higher resistance of the sulphide coating, the current flow through relay or switch contacts is usually less than the predetermined value, hence a wrong signal is sent to the control device. This is common on transformer tap-changer positions remote indication, steam flow and steam pressure value indications and level transmitters.
- 2) *Under-voltage:* Voltage drop due to higher contact resistance across H₂S contaminated contact causing magnetic contactor chattering, burning/welding on the pressure switches, protective relays, normally-closed control switches and limit switches. The indication lamps dim or may not give light at all; solenoid valves may not operate.

8.4 Cases of H₂S gas effects at Olkaria I

Table 3 gives a history of some of the recorded operational and maintenance problems as a result of hydrogen sulphide gas contaminating electrical equipment and control systems.

TABLE 3: Summary of some of the observed operational and maintenance problems caused by H₂S gas at Olkaria I (KenGen, 1992-2001)

Date	Observed problem	Cause of problem	Remedy
Feb. 1992	Unit 1 160 kW circulating water pump 'A' motor could not start.	Local panel 'Stop' switch contact resistance about 100 Ω.	Switch contacts cleaned of the black/deep-blue sulphide coating.
July 1992	Unit 2 generator circuit breaker fails to open.	Contacts for the generator low forward power protection relay had welded together.	Contacts forced to open then cleaned/smoothed with a fine file.
March 1993	Unit 1 and Unit 2 generator circuit breakers overheating.	Some of the circuit breakers' primary junctions were burnt.	Cleaned and replaced the primary junctions. Contacts were smeared with petroleum jelly.
Dec. 1993	Wire for generator over-current protection relay's 'flag' circuit broken.	The bare stranded 1 mm ² tinned copper wire found brittle and worn out.	The wires replaced with new ones.
Aug. 1994	Unit 1 fire fighting system not responding to tests.	'Reset' switch contact resistance to about 100 Ω.	Switch contacts cleaned
May 1996	Unit 1 generator circuit breaker found with low SF ₆ gas press.; 3.4 kg/cm ² instead of 6 kg/cm ² .	Blue phase primary junction was found burnt and gas leaking at the bushing.	The circuit breaker was replaced with a new one. Old breaker repaired later.
Feb. 2000	Unit 2 cooling tower fan 'C' 94 kW motor could not start.	A 'local/remote' changeover switch contacts resistance over 50 Ω.	Switch contacts cleaned.
March 2000	Unit 1 instrument air compressors 'A' and 'C' tripping too frequently on unjustifiable overload.	Thermal overload protection device malfunctioning due to overheating supply terminations.	The supply termination lugs were replaced and tightly crimped.
April 2000	A bare 95 mm ² multi-stranded copper earthing broken near seal-pit area.	The copper strands were severely corroded and broken.	An insulated 120 mm ² was laid across the broken conductor.
Nov. 2001	Unit 3 cooling tower fan 'B' motor could not start.	The 250 A fuses and fuse carriers burnt.	The fuses and the fuse carriers replaced.

8.5 Recommendations

The following methods can help to overcome corrosion on indoor electrical equipment:

- Where H₂S levels are high, air conditioning systems should be fitted with special filters and special precautions should be taken to prevent unfiltered air from entering clean areas at all times. All sensitive equipment shall be located in a positive pressurised and H₂S filtered room.
- Monitoring of doors in cleaned air rooms (alarm if door stays open for several minutes).
- Check and replace the sensitive relays with numerical (digital) types (no moving contacts).
- Gold alloys and platinum plated contacts may be used in electrical relays.
- Cleaning and smearing (covering) the electrical contacts with special conductive grease.
- Specification of H₂S rated instruments and connections.
- Specification of gold-plating on printed circuit board connections.
- Provision of control cubicles with anti-condensation heaters.
- Varnishing and painting indoor items.

The following methods can help to overcome corrosion on outdoor electrical equipment:

- Use of tinned and epoxy painted bulk copper.
- Use of corrosion resistant materials such as aluminium, stainless steel, etc.
- Use of heat shrink material on exposed copper.
- Epoxy encapsulation of small components.
- Making a careful selection of paint systems and sealing gaskets.
- Mild steel galvanising.
- Reduce the H₂S concentrations in the atmosphere by ejecting the non-condensable gases at very high heights.
- Supply of cleaned air to outdoor cabinets.
- Use of H₂S abatement systems for emissions control such as Stretford process, LO-CAT process, AMIS process, Selectox process (Rivera, 2007).

9. DCS IN RELATION TO SCADA

The *Distributed control system* (DCS) at Olkaria II plant is, in many aspects, similar to the *Supervisory control and data acquisition* (SCADA) system. SCADA system is the technology that enables a user to collect data from one or more facilities and /or send limited control instructions to those facilities from a central computer (Stuart, 1999). SCADA and DCS are both specialized to perform different functions in process control.

Features of DCS:

- i. More emphasis is on process-control functionality;
- ii. Process oriented, it looks at the controlled process and presents data to operators as part of its job;
- iii. Primarily for the implementation of sequential control;
- iv. Typically in one plant;
- v. High availability of power;
- vi. Fast and robust communications;
- vii. Control equipment reside in a temperature-controlled room;
- viii. Always connected to its data source. Redundancy is usually handled by parallel equipment, not by diffusion of information around a distributed database.

Features of SCADA:

- i. More emphasis is on system database and data-gathering system;
- ii. Data-gathering oriented, it is mainly there to collect the data – though it may also do some process control;
- iii. Primarily for integrating a large number of remote locations and concentrating the logic processing at a central master station;
- iv. Usually distributed across a wide area / region;
- v. Power may be intermittent or off;
- vi. Communications can be slow and drop out regularly;
- vii. Equipment may be installed in a hostile environment;
- viii. Gets data and performs control over a potentially slow, unreliable communications medium. Redundancy is usually handled in a distributed manner.

There is, in several industries, considerable confusion over the differences between SCADA systems and DCS Systems. Generally speaking, a SCADA system coordinates, but does not control processes in real time. As communication infrastructures with higher capacity become available, enabling reliable, high speed communications over wide areas, the differences between SCADA and DCS will fade. By looking at a customer's system requirements specifications, a careful analysis of the data collection and data quality requirements will indicate if a SCADA-type or DCS-type system is appropriate.

10. CONCLUSIONS

From the research study, it can be concluded that it is worthwhile for KenGen to invest in a digital control system for Olkaria I, and a remote monitoring and control system for Olkaria I and II for the following main reasons:

High reliability:

- Duplicated redundant processors, network and power supply units help ensure reliability. This means that, in the event of failure, switchover can be made to the standby unit of the duplex system without adversely affecting control.
- Each MPS CPU is provided with a complete set of self-diagnostic functions. Even in the unlikely event of a system failure, the MPS CPU's self-diagnostic functions and indication features make it easy to locate the failure and restore the system.
- The low-traffic communication technology used to monitor and control plants is based on the internet technology. It is highly reliable and creates only a low traffic load, enabling control and monitoring by telephone lines with no need for a new infrastructure such as optical fibres.
- The advanced alarm functions have several ways to quickly inform operators of abnormalities, and to help investigate their sources. The system comes with an alarm summary, two-line message, alarm-group display and event trace. It also provides alarm setting and event printing functions.
- Remote monitoring and control reduces the time needed for failure diagnosis and repair.
- The digital control system's proven ability to run 24 hours a day, 365 days a year. If a memory leak that might cause a system freeze occurs, an appropriate circuit detects and reports it as an alarm to reset the PC before the freeze occurs and releases the memory.

High operability:

- Excellent controllability is achieved through the powerful Intel Celeron/Pentium processor and high-speed process I/O scheme. The high-speed MPS CPU is able to perform almost any type of arithmetic computation, including efficiency/performance calculations and more.

- The OPS uses Microsoft Windows as the operating system. Windows is prone to freeze (a window suddenly stops and does not recover until the power is turned off and on again) and may not be suitable for operating and monitoring a plant in terms of reliability. But the digital control system has the operability of Windows and at the same time high reliability that is based on a design concept that totally differs from conventional control systems. The MPS CPU has the data collection and alarm detection features. Even if the OPS goes down, the required functionality is never lost. The operating system of the MPS CPU is pSOS. When the OPS needs data, it asks the MPS CPU or the ACS. Therefore, even if the OPS freezes and is reset, functional degeneration such as missed alarm detection or missed trend data does not occur at all.
- The user friendliness and widespread proficiency in MS Windows based user-machine interface helps to achieve high operability.
- The logic and graphics creation tools are based on VISIO, a CAD tool which is renowned for its user friendliness, so systems can be designed by dragging and dropping. The logic diagrams created in VISIO are directly saved as formal drawings, allowing for consistency between the actual logic and drawings.
- The engineering software tools make it possible to perform easy system maintenance of anything from control logic modification to system configuration.
- Advanced data collection and storage features.
- Many interfaces are available to enable the connection with external systems.

ACKNOWLEDGEMENTS

I would like to say ‘thank you’ to my employer, Kenya Electricity Generating Company - KenGen, for granting me the opportunity to attend this training. I am also grateful to Dr. Ingvar B. Fridleifsson, director of the UNU Geothermal Training Programme, for offering me the chance to participate in this training, and Mr. Lúdvík S. Georgsson, deputy director, for his successful organization of the programme. Many thanks go to Mr. Jóhann Thór Magnússon, my supervisor, for his good guidance, sharing his knowledge and experience and supervision of this work. Sincere thanks to Ms. Thórhildur Ísberg, Mrs. Dorthe Holm and Mr. Markús A.G. Wilde for their useful help and care all through the training period. I thank my parents, for their constant prayers, support and encouragement during the entire training period. My special thanks go to my son Michael, who at a very tender age, demonstrated great endurance and patience during my long absence from home, and to my unborn baby, who gave me great company during all my days in Iceland. This work is dedicated to my children, with unconditional love. May God bless them; grant them the desires of their hearts and great happiness in life. Finally, I thank the Almighty God, who made all these things possible.

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