Course Lecture

Metering Technology

&

AMR Application

Developed by

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Metering Technology & AMR Application

Target Audience: Middle and Junior Management (Executive Engineer, Assistant Engineer, and Junior Engineer or their equivalent)

Objective: The objective of this theme is to understand the concept and design of metering technology and use of AMR Application in distribution system.

I. Automated Meter Reading Technology including data management
II. Accreditation of meter testing laboratories.
III. Metering Protocol

Training Modules:

1. **Open Communications Standard for Metering**
   - 1.1. Metering Protocols
     - 1.1.1. Implementation of a common metering standard in Indian Context
     - 1.1.2. Features of DLMS-COSEM Standard

2. **Automatic Meter Reading**
   - 2.1. Automated Meter Data Acquisition
     - 2.1.1. Various means of Communication for AMR
     - 2.1.2. Network topologies in use to acquire meter data
     - 2.1.3. Software Application for Meter Data Acquisition (AMR)

Abbreviations

AMI	Advanced Metering Infrastructure
AMM	Advanced Meter Management
AMR	Automatic Meter Reading
ANSI	American National Standards Institute
API	Application Program Interface
ASIC	Application Specific Integrated Circuit
BIS	Bureau of Indian Standards
CBIP	Central Board of Irrigation & Power
CDF	Common Data Format
CEA	Central Electricity Authority
CFC	Common Format Converter
CFW	Common Frame Work
CMRI	Common Meter Reading Instrument
COSEM	COmpanion Specification for Energy Metering
CPRI	Central Power Research Institute
DISCOM	DIStribution COMpany
DLMS	Device Language Message Specification
EPRI	Electric Power Research Institute
IEC	International Electrotechnical Commission
IEEMA	Indian Electrical and Electronics Manufacturers Association
MIOS	Meter Inter Operability Solution
OBIS	OBject Identification System
PSTN	Public Switched Telephone Network

XML eXtensible Markup Language

Module -A
Open Communications Standard for Metering

1. Introduction

Smart meters, AMI and AMR have created a lot of interest in the past few years. One of the driving forces has been the directives on energy end-use and energy services, together with market liberalisation and a general trend for energy saving and environmental concern by consumers. This has created a demand for interoperable solutions for meter reading. In India, digital microcontroller/ASIC based energy meters are in extensive use in power distribution monitoring. These meters measure and record energy consumption & load profile for fixed no. of days. Energy meters stores monthly energy consumption data which gets downloaded to the Meter Reading Instrument and further to the Base Computer Software (BCS). The consumption data from BCS gets imported to the billing software after which bills are generated and dispatch to the consumer. This complete process takes too much time as meters are of different make / manufacturer and BCS is also manufacturer specific while doing AMR (Automatic Meter Reading) or RMR (Remote Meter Reading) using hand held devices. Hence power distribution utility requires a system / products by which multiple manufacturers make meter having different communication protocol, the communication media and database should be interoperable or there should be some open communication standards for energy metering followed by all manufacturers. Efforts has been done in both the directions to make existing meters usable for AMR or AMI as well as new standards evolved for new energy meters.

1.1. Interoperability

Interoperability provide capability to communicate, execute programs, or transfer data among various functional units in a manner that requires the user to have little or no knowledge of the unique characteristics of those units. This means ability of a system or a product to work with other systems or products without special effort on the part of the customer. This is important for effective use of metering assets by means of automation, data retrievals, processing & analysis. In this context, many attempts have been made around the world; people have tried to evolve common standards of communicating with and interpreting data from the meter. These approaches so far has been to adopt one of the many proposed standards of data exchange for electronic meters. Some attempts have also been made to use standards of data exchange coupled with standards of data interpretation. The interoperability should be chosen on the basis of application area and its practical usage. Since the utility requirement is to acquire meter data from meter for bill generation, monitor important distribution parameters, and generate exceptions / MIS reports for proper planning, monitoring, decision support and taking corrective actions on the business activities by the management, then in that case interoperability at system level is very much required.

1.2. Open Metering Standards

With development of electronic meters having possibilities of metering data being integrated into business processes of service providers and in turn with generating agencies, thus opening up multiple opportunities in power system management at both micro and macro levels and being guided by the National Electricity Policy of the Central Government after enactment of the Electricity Act 2003, the Committee initiated the work of formulating standards on Data Exchange from Electricity Metering Equipment in 2006. Two options were taken up for interoperable use of meters in a data network. In 2007 the Committee decided as one option, to adopt the International Standard IEC 62056 already available in various parts. However it was felt that only adoption was not sufficient for proper implementation, as the selective features of the standard available at that time were not adequate for use by different utilities collectively. In view of urgent power reforms programme of the central Government and the metering data integration involved, the Electrotechnical Division Council in April 2008, while appreciating the other option of Common Framework based solution being developed by Indian Electrical and Electronics Manufacturers Association (IEEMA), advised the committee and divergent stakeholders for rapid implementation of the IEC standard available. The Committee inducted experts and held a series of meetings for evolving this specification for proper implementation of the IEC standard based on open protocol and wide ranging selective features thereof, for application in Indian networks.

Distribution Line Message Specification (DLMS) with functionalities of Companion Specification for Energy Metering (COSEM) based on open protocols and maintained by Device Language Message Specification User Association, DLMS UA, Geneva, in the form of four technical Reports, namely “Blue”,, “Green”, “Yellow” and “White” Books, have been adopted by IEC on regular basis in the international standards mentioned above for interoperable use of electricity meters in a data network. The continuous development of DLMS / COSEM open communications protocols for data retrieval, update, and reconfiguration of metering devices, has enabled diverse operators to access safely and quickly data from metering equipment provided by diverse manufacturers.

2. Metering Protocols

For a grid to be “smart”, a well-designed layer of intelligence placed over the assets of a utility should provide the basis for new fundamental grid applications. For example, demand response and VPPs (virtual power plants) would require tight integration of smart meters, home networks and distribution transformers or substations. This illustrates the importance of an appropriate communication infrastructure on multiple levels. In this section, a short introduction to each metering communication standard is presented. The relevant criteria for selection are:

1) **Openness of the standard.** Because of the smart grid context, interoperability and extendibility must be guaranteed across different devices and manufacturers. Therefore, only open standards have been considered in this course.

2) **OSI layer position**. Does the standard mostly concern hardware aspects (such as IEC 61334-5 or IEC 62056-21) or is it a data-model (e.g. DLMS/COSEM) or both (such as KNX and LonWorks)? A rough sketch of this is shown in Fig. 1.

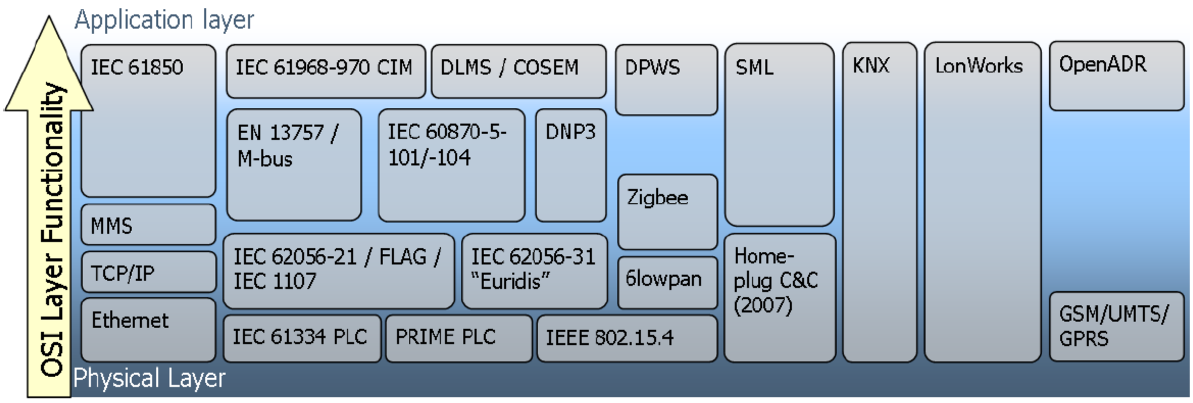

Fig.1: OSI layer placement of metering communication standards

3) The intended use case of the standard and what functionality it provides. This leads to a separation between the smart home and the smart grid, with the former focusing on in-home communication and automation (such as domotics) and the latter more on long-range and management aspects.

4) The maturity and if applicable, the performance and scalability.

2.1. IEC 61850 and UCA 2.0

The Utility Communications Architecture was developed by the EPRI at the beginning of the "90s. In "97 the IEC and the EPRI harmonized their efforts to develop a common international standard which led to the IEC 61850 specification. IEC 61850 can therefore be considered as a superset of UCA 2.0 and is primarily designed with intra-substation communication in mind, but it can also be used between substations or control centers (IEC 62445-1 and -2) and for metering applications. IEC 61850 is placed at the application layer. All services and models are designed in an abstract form called ACSI (Abstract Communication Service Interface) and thus independent of the underlying medium. ACSI is then mapped to protocols such as MMS2 and TCP/IP over Ethernet. In addition to ACSI, IEC 61850 provides the multicast based GSE (Generic Substation Events) as a way to quickly transfer event data over an entire substation network. Furthermore, part 9-1 and -2 specify a process bus for use with IEDs. The basic concept of IEC 61850 consists of a hierarchical and object-oriented information model with devices, nodes and classes that can hold different attributes and data. These are self-describing and every vendor is required to publish their extensions. Since January 2009, part 7-420 has been added to IEC 61850 and covers distributed energy sources and storage. It could even be used for V2G (Vehicle to grid) activities. Also of interest is IEC

61400-25, an adaptation of 61850 for wind-turbines. IEC 61850 is a flexible, mature and future-proof standard that is most likely to follow through in the utilities sector.

2.2. IEC 61334 PLC

Part 5 of the IEC 61334 suite of standards defines several narrowband PLC (Power Line Communication) systems, part 5-1 S-FSK being the most used. The upper OSI layers (including the DLMS protocol in part 4-41) are also specified but optional. Because the allowed frequency range (3 kHz to 148.5 kHz in Europe) and transmission power is small, so is the bandwidth, limiting suitability for (e.g.) TCP/IP communication. A typical PLC system consists of a backbone coupled concentrator close to a MV/LV transformer. All traffic on the line is initiated by the concentrator, which acts as a "local relay" for a management center. More recent narrowband PLC technology include sophisticated techniques such as OFDM (Orthogonal Frequency-Division Multiplexing) to provide higher data rates, and focuses on broadband solutions operating in the 1-30 MHz band. Also worth mentioning is the installation of filters to improve SNR ratios. Despite the difficulties, PLC technologies are at a clear advantage for utility companies as they can have full control over the network and are relatively cheap.

2.3. PRIME PLC

PRIME stands for Powerline Related Intelligent Metering Evolution and defines the lower layers of an OFDM based PLC narrowband system that operates within the CENELEC A-band. Raw data rates of up to 130 kbps are possible and an IPv4 convergence layer should allow efficient transfer of TCP/IP traffic. There are however still some rough edges:

i. As development started at the end of 2007 and the PRIME alliance was founded in 2009, PRIME is still an immature standard.
ii. The standard still lacks conformance tests.
iii. IEC 61334-5 and PRIME are not designed to coexist on the same network segment.
iv. No test results yet about real-world operation, interference and meshed network performance.

Alliance coordinator Iberdrola, a Spanish utility, is developing an open smart metering architecture around PRIME and has commenced a pilot project in 2009.

2.4. IEC 62056-21 / IEC 61107

The IEC 62056-21 standard is sometimes referred to as "Flag" or by its old name IEC 1107 [10]. Part 21 "direct local data exchange" was published mid 2002 and describes software protocols and hardware suitable for data exchange with utility meters. It is similar in nature to US standard ANSI C12.18. At the hardware side, an optical interface and a two-wire system are described. On top of this, asynchronous half-duplex ASCII-based RS232 data transfer is used. Different operating modes are specified, labeled from A to D, which differ in baud rate, directionality and security. A special mode E allows the use of DLMS/COSEM via HDLC (High-Level Data Link Control, IEC

62056-46). As one of the first meter data exchange standards, IEC 62056-21 is widely used today. However it does not use a data model or uniform memory mapping. Therefore meter communication requires manufacturer specific information, limiting interchangeability.

2.5. EN 13757 / M-Bus

EN 13757 (Meter bus) is an European standard for the remote interaction with utility meters and various sensors and actuators which was developed at the University of Paderborn. M-Bus uses a reduced OSI layer stack. Part 2 describes the physical and link layers, while part 3 specifies the application layer. Several physical media are supported including twisted pair and wireless M-Bus (in the ISM band). The twisted pair medium typically operates at 2400 to 9600 baud and a single segment can be up to a few km"s long. Primary focus of the standard is on simple, low-cost, battery powered devices. Noteworthy is the support for DLMS/COSEM in the lower layers. The DSMR (Dutch Smart Meter Requirements) specifies wired and wireless M-Bus as the means of communication between a metering installation and other (gas, water, ...) meters, albeit with improved security (AES instead of DES). As this standard is already widely used in meters and reasonably future proof it is a good contender for local data exchange in the smart grid.

2.6. DLMS/COSEM or IEC 62056

DLMS (integrated in IEC 62056) stands for Device Language Message Specification and is an application layer protocol, specifying general concepts for the modeling of object-related services, communication entities and protocols. COSEM is the Companion Specification for Energy Metering. It comprises metering specific objects based on OBIS (Object Identification System) codes for use with (x)DLMS. xDLMS is an extension to DLMS and describes how to access attributes and methods of COSEM objects. COSEM defines a number of standard interface classes, called objects when instantiated, containing attributes and methods to describe some required functionality. An attribute is used to describe the aspects of some data, while methods are used to read or modify it. There are four groups of COSEM interface classes, relating to storage, access control, time and scheduling and communication. Standardized building blocks can be combined to model a metering device in a hierarchical structure, thus allowing the construction of complex metering systems. Two mandatory objects per device regulate access control and identification. When a meter is read, the necessary attributes of certain objects are accessed using an xDLMS service and transformed into a series of bytes, called APDUs (Application Protocol Data Units). OBIS naming is used to identify COSEM objects to make them self-describing. A full list of standard OBIS codes and valid combinations of standard values in each group is maintained by the DLMS User Association. To support future functionality and enable innovation and competition, specific elements such as new OBIS codes, attributes, methods and interface classes are allowed. However the information on such elements has to be made available by the manufacturer. DLMS/COSEM is based on a client/server structure in which the data collection system acts as a client requesting data from the servers (pull operation), in this case the meters. The communication protocol stack (called a profile) is completely independent of the application layer so servers and clients may independently support one or more communication profiles to communicate over various media. The COSEM model - modeling the application process - and the application layer - making use of this model - remain the same. Future additions will provide push operation (client to server) and more efficient data exchanges by using compression techniques. DLMS/COSEM is positioning itself as the all-round contender for smart grid communication. The support for DLMS/COSEM in a lot of other standards (such as M-Bus, IEC 62056-21, -31 and recently Zigbee), projects (Dutch DSMR) and existing meters illustrate this.

2.7. IEC 62056-31 ”Euridis”

Euridis is a standard for remote and local meter reading introduced at the beginning of the 90s and in 1999 it was integrated into IEC 62056 as part 31. Euridis uses a twisted pair cabling system, the local bus, onto which all meters in a building can be linked. A magnetic coupler then allows connecting a handheld unit for readout or programming. The bus can be up to 500m or 100 devices and allows a data rate of 1200 baud half-duplex. Today, nearly 10 million devices, mostly in francophone countries, communicate using Euridis. At the beginning of 2009, the Euridis+ protocol stack was announced, supporting DLMS and allowing 9600 baud, while retaining backwards compatibility. Publication of Euridis+ was expected at the end of 2010. The scope of Euridis is clearly local meter reading with HHUs. As with part 21, Euridis does not have a common data model, but the upcoming Euridis+ will correct for this.

2.8. ZigBee (Smart Energy Profile)

ZigBee is a low-power wireless communications technology designed for monitoring and control of devices, and is maintained and published by the ZigBee Alliance. Home automation is one of the key market areas. Zigbee works on top of the IEEE 802.15.4 standard, in the unlicensed 2.4 GHz or 915/868 MHz bands. An important feature of ZigBee is the possibility to handle mesh-networking, thereby extending the range and making a Zigbee network self-healing. The Zigbee Smart Energy Profile [24] (numbered 0x0109) was defined in cooperation with the Homeplug Alliance in order to further enhance earlier HAN (Home Area Network) specifications. The profile defines device descriptions for simple meter reading, demand response, PEV charging, meter prepayment, etc. Recently a collaborative effort between the Zigbee Alliance and the DLMS UA was announced to define a method to tunnel standard DLMS/COSEM messages with metering data through ZigBee Smart Energy networks. Considering the low power requirements, robustness, availability of cheap Zigbee “kits” and the specific profile for metering applications, Zigbee has a lot of potential in home area networks.

3. Implementation of a common metering standard in Indian Context

India has a large installed base of energy meters procured from numerous Indian and International manufacturers serving the Indian market. Constant monitoring and tracking of metering assets and electric usage have become very important for all the electricity

Utilities. The requirement of complex analysis and load management applications has also emerged in the current scenario. Therefore, collection, validation and transformation of data from a large number of meters have to be carried out to realise benefit from the investments on the meters.

Evolution of the electricity meters using microprocessor based technology has historically taken place with proprietary protocols to provide internally stored values in formats unique to the manufacturer. With the change in requirements of the utilities, additional parameters and features have been added resulting in different versions of meters even from the same manufacturer. The users of these multiple versions of meters are burdened with multiple data formats on proprietary protocols. The Utilities have to buy and maintain separate Application Program Interface (API) software from each meter manufacturer in order to make use of the data from different versions of meters. In addition third party handheld readers and remote metering systems have to be updated for every new meter type/ version added to the utility system. The proprietary protocols results in dependence of the DISCOMs on the vendors of meters as the APIs are needed for integration of metering information with the IT infrastructure. This resulted in focus on the development of open protocol.

3.1. Interoperability Standard for Energy Meters in India

The interoperability is the capability of the data collection system to exchange data with meters of different makes and the capability of the metering equipment to exchange data with different type of data collection systems. This necessitates the presentation of the meter data in predefined common formats and address system for the meters which results in compact, low cost and efficient programming effort for AMR/AMM applications using IT infrastructure. The evolution of enhanced capabilities afforded by microprocessor based meters and the desire to harness the benefits of such capabilities led to development of open protocols independent of make/manufacturer. With the availability of open protocols, many options and features become available to the purchaser or software developer who may want to take advantage of them to optimize their operations or to maximize their commercial benefit.

American National Standards Institute (ANSI), Automatic Meter Reading Association (AMRA) and Canadian Standards bodies collaborated to develop a solution to overcome the obstacles in the meter communications as discussed in preceding paragraphs. All the stakeholders viz. utilities, meter manufacturers, third party software providers, consultants and others interested in the field were involved to evolve ANSI protocol standards which is an open protocol. The protocol is being widely used in US and Canada.

Concurrently, the International Electrotechnical Commission TC-57 evolved DLMS (Device Language Message Specification) IEC 61334-41 to cater to the requirement of the open protocol for communication. Later TC-13 adopted this protocol and modified it as IEC 62056.

To achieve interoperability of meters, a forum of nine Indian meter manufacturers under the aegis of IEEMA started working since 2002 on MIOS through two committees viz. Core Committee and Technical Committee. MIOS defines data format at the data exchange level rather than at the meter communication level. This requires Common Frame-Work software (CFW) which serves as user interface and initiates actions to perform specific tasks. CFW is a master program which invokes Manufacturer reading Module (API1) to read the meter and store data and provides links to other application programs and database. The working of the common protocol model and MIOS model is illustrated in the Fig. 2 below.

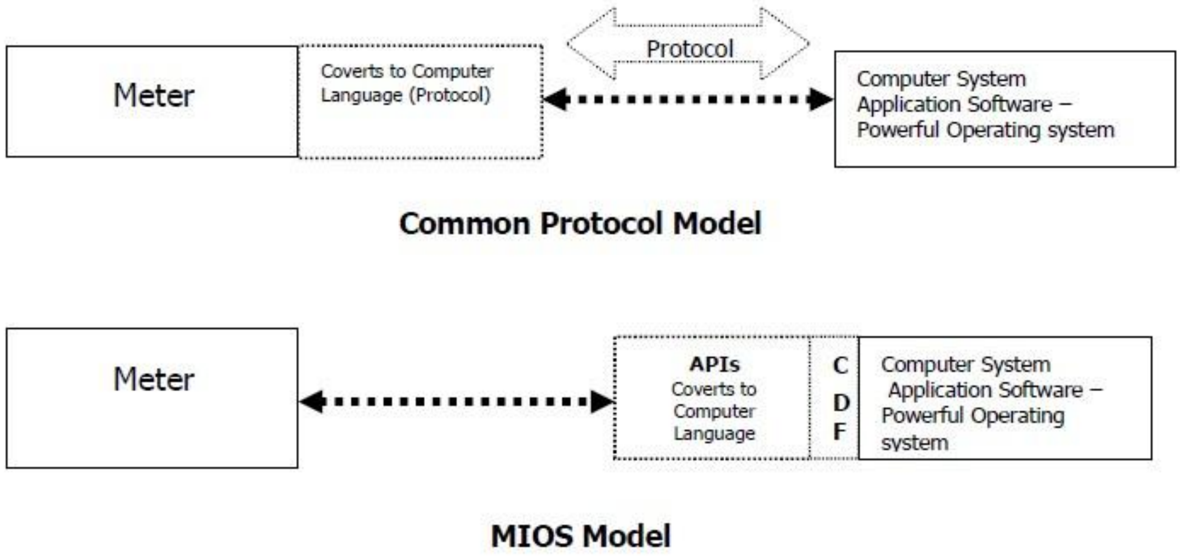

Fig. 2: Working of Common protocol and MIOS model

The MIOS (Meter Interoperability Solution – A Forum under IEEMA) solution provides interoperability at system level in India. All meter manufacturers will have to supply APIs complying with the specification. The executable file will allow reading the meter data, check security, interpret and provide data in a common agreed data format. Such an agreed data format should be flexible for future expansion and adaptable to various customer needs. Open formats using languages like XML (eXtensible Markup Language (XML)) is quite well suited for this kind of application. This will much more cost effective for both utility & meter manufacturer vis-à-vis to consumer also. The system based interoperability also allows other parties (like software vendors / system integrators) to come & join. Hence it is proposed that an interoperability standard be so defined that it meets all the requirements outlined above and does not lose sight of the key objectives of the electricity utilities. The system level interoperability will provide seamless integration. In this scenario when there will be different components like meter, communication channel / media, database, and other IT infrastructure, interoperability plays a major role. The "interoperability" requirement should be seen with the installed meters / legacy meters as well as new purchases and also less cost effective solutions.

The MIOS Universal Meter Reading & Common Format specification fulfils following objectives:

a) To provide Common framework (CFW) for software & to specify interfaces so that modules can be attached with it. It is envisaged that the common software will have minimum functionality attached which is described below.
   i. To provide module (API) for reading meter.
   ii. To provide module (API) for exporting data in common format so that 3rd party software which is using the data for further processing will have uniform way of handling the data irrespective of the manufacturer from which the meter is bought.
   iii. To provide module (API) for checking integrity of the data.

b) The common framework will ensure that
   i. Future expandability is easy to accommodate technically & administratively
   ii. Backward compatibility for existing meter base
   iii. Scalability of the software
   iv. Accommodating different utility
   v. Simplicity of „maintenance"
   vi. Security of the data

In the arrangements made by MIOS, each meter manufacturer provides a set of Application Programming Interfaces (API) for collecting data from their meters. Two API"s have been developed:

(i) API for collecting data from meters and converting to respective manufacturer specific format so that the data can be interpreted by the manufacturer"s application software.

(ii) API for converting data from the manufacturer specific format to a Common Data Format (CDF) in XML (eXtensible Markup Language) so that any third party software can use it for customer business applications. XML is well suited for platform independent open applications of this nature and is also easily adaptable to future expansions.

The detailed MIOS specification "Universal meter reading and common format" version 3.0 is available for free download from www.meteringindia.com website. The MIOS common framework will provide interface for APIs to be plugged in. The diagram shown in Fig. 3 shows three important functionality reading the meters & common format converter being plugged in the CFW. This will ultimately result in Common Data Format (CDF).

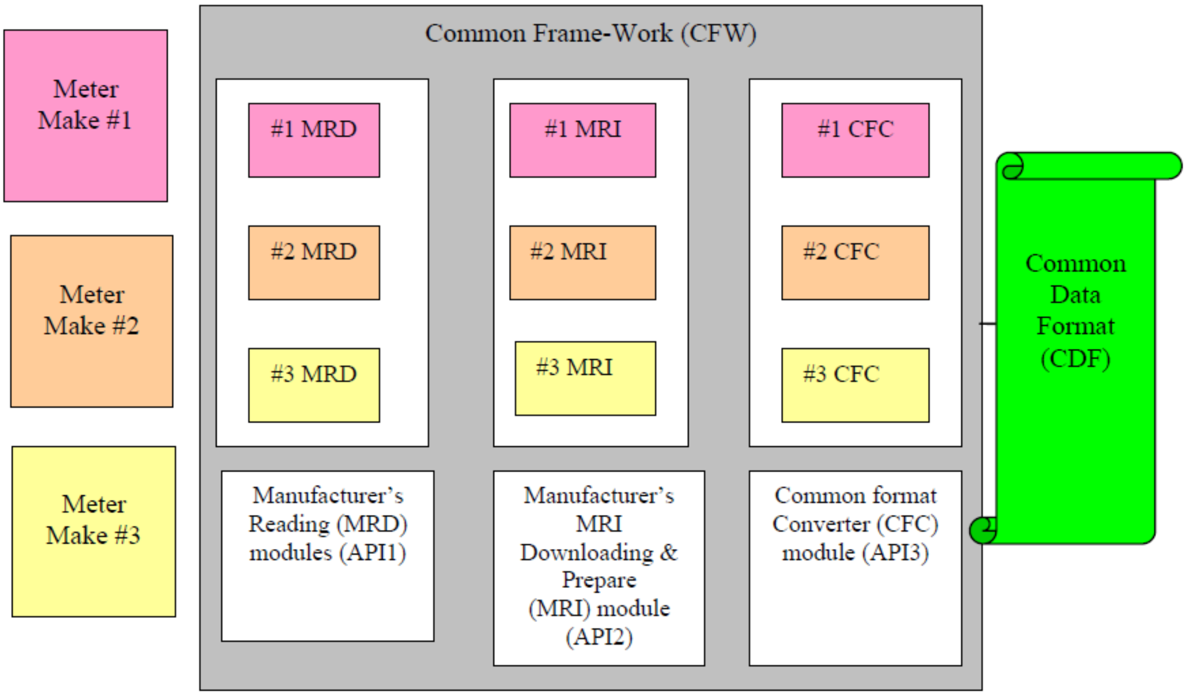

Fig. 3: MIOS Common Frame Work

3.1.1. Responsibility of CFW

i. CFW is to be designed for Microsoft Windows platform.

ii. CFW is master program & each manufacturer specific API is a slave (passive) module.

iii. All action will be initiated by user interface of CFW and CFW will in turn invoke API"s to perform meter specific task.

iv. To create & maintain manufacturer specific folders for containing file in manufacturer specific format & one for containing common data format file folder.

v. The CFW shall provide facility

   a. To maintain consumer database (to co-relate factory serial number & consumer number)
   b. To schedule meter reading
   c. To decide & supply information to be read from meter to reading API
   d. To check up the result code & decide future course of action.
   e. To convey error by suitable means such as unable to invoke the API, unable to establish connection & so on.
   f. To invoke convert API for conversion of data in CDF format.
   g. Manufacturer folder: There shall be three folders in manufacturer folder.
      i. CFW \ Manufacturer \ ABC \ ConversionPending
      ii. CFW \ Manufacturer \ ABC \ ConversionDone
      iii. CFW \ Manufacturer \ ABC \ ConversionError

iv. CFW \ Manufacturer \ ABC \ API

Manufacturer API with related files supplied will be kept here. Any file related to OS or environment will be supplied by manufacturer & will be installed as per the instructions given in the API release note.

h. To maintain common Data Format (CDF) folder in which common data format files will be kept. The location of common data format file folder will be

i) CFW \ CDF \ …

vi. CFW does not know how APIs work.

vii. CFW will not change the information for any of the tags even if CFW believes that the information supplied by the meter is obsolete & out of date.

viii. Multiple instances of the same APIs will not be invoked by CFW.

ix. House keeping is CFW‟s responsibility & method of doing house keeping should be defined & published by the CFW.

x. The agency desiring to use APIs will have to enter with a legal contract with manufacturer. Each time API is deployed the manufacturer‟s written permission is required.

xi. CFW and API should be operated from the same machine. However different APIs can be operated from different machine as long as it is accompanied by CFW.

xii. Configuration files generated as a input to API should have all XML tags and attribute names in upper case.

3.1.2. Responsibility of manufacturer's API

The manufacturer‟s API will follow the rules as described below:

a. All APIs will be executable exes or batch files (i.e. EXE or .BAT).
b. All APIs are controlled by CFW. No API will handle screen or keyboard request directly.
c. All messages will either be passed on via configuration file or via the command structure described.
d. APIs will transfer the messages via MII protocol. Longer message to API will be passed on via configuration file.
e. APIs should pass on meaningful message in case particular command is not handled by it.
f. Error reported can be meter specific or API specific. API should give clarity about it.
g. Success of the work is to be declared only if last step of the operation is done such as file generated for a given command is stored at the indicated (or predefined) location.
h. APIs may drop some of the tags due to unavailability of information from the meter.

i. API will give acknowledgement of any command within 3 seconds.
j. API shall take path/filenames and other parameter specified in configuration files provided to the API and should not hardcode anything. Tag values written in this document are suggested paths and are for example only.
k. Result file and common data format file generated should have all XML tags and attributes in upper case.
l. API should create log file which can be used for debugging/troubleshooting purpose.

3.2. Open Metering Standards in India

The two major options available in India to facilitate data collection and Interoperability of meters are:

a. Adoption of non-proprietary open common communication protocol.
b. Application Program Interface software for each make/type of electronic meters i.e. MIOS

The option of MIOS for existing installation and legacy meters has already been discussed in section 3.1. The American National Standards Institute (ANSI) and International Electrotechnical Commission (IEC) have developed non proprietary open protocols. Owing to the alignment of the Indian Standards with those of IEC, only IEC standards have been considered.

3.2.1. International Electrotechnical Commission (IEC)

The International Electrotechnical Commission (IEC) is the leading global organization that prepares and publishes international standards for all electrical, electronic and related technologies. The IEC is made up of members, called National Committees (NC), and each NC represents its nation's electrotechnical interests in the IEC. This includes manufacturers, distributors and vendors, consumers and users, all levels of governmental agencies, professional societies and trade associations as well as standards developers from national standards bodies. BIS is actively involved in the activities of the IEC and has participation status in 67 TCs / SCs of IEC. It may be mentioned that depending on suitability to Indian conditions and to align the IS Codes in line with IEC Codes, most of the IEC documents are also adopted for publication as IS Code under dual number scheme of BIS.

3.2.2. DLMS and IEC- 62056

The DLMS/COSEM specification is standardised by DLMS UA, Geneva and released later as IEC standard under TC-13 for meter Communication Protocol. It is a meter modelling standard to give presentation mechanism of the meter features at its communication interface irrespective of the manner in which the meter has been built. Therefore, the standard itself does not define a meter but provides standard object model for modelling any standard electricity meter and provides pre-defined external interface for communication purpose.

3.2.3. BIS and IEC - 62056

India is a Participation Status Member of the TC-13 relating to electrical energy measurement, tariff and load control. CPRI are the convener of ET-13 Panel P1 to look into the metering protocols and their adoption for Indian conditions. The BIS has already circulated six documents of IEC 62056 relating to protocol for data exchange for meter reading etc. to the Members of its Sectional Committee (ET-13) and others, seeking their comments and views for adopting these as Indian Standards. The documents circulated by BIS are listed below:

IEC No.	BIS Document No.	Document Particulars
62056-21	ETD 13 (5997)	Electricity Metering – data exchange for meter reading, tariff and load control – Part 21 : Direct local data exchange.
62056-42	ETD 13 (5998)	Electricity Metering – data exchange for meter reading, tariff and load control – Part 42 : Physical layer services and procedures for connection oriented asynchronous data exchange.
62056-46	ETD 13 (5999)	Electricity Metering – data exchange for meter reading, tariff and load control – Part 46 : data link layer using HDLC protocol.
62056-53	ETD 13 (6000)	Electricity Metering – data exchange for meter reading, tariff and load control – Part 53 : COSEM application layer.
62056-61	ETD 13 (6001)	Electricity Metering – data exchange for meter reading, tariff and load control – Part 61 : Object Identification System (OBIS)
62056-62	ETD 13 (6002)	Electricity Metering – data exchange for meter reading, tariff and load control – Part 62 : Interface

3.2.4 Recommendation on Standardization of Metering protocol

The Ministry of Power have constituted a High Level Committee under the Chairmanship of Member (Grid Operation & Distribution), CEA comprising members from Electricity Distribution Companies, IEEMA, NTPC, Director General, CPRI, for standardization of meter protocol to enforce inter- operability of different makes of meters, both existing and to be installed in future in the power sector.

After detailed deliberations by the members of the committee on various aspects of implementation of open protocol for metering communication, to achieve interoperability of the meters, there was a consensus on adoption of open protocol as per IEC 62056 series of standards. The Committee recommends implementation as under:

1. The new meters to be procured in future may conform to the open protocol as per IEC 62056 series of standards.
2. For the legacy meters utilities may adopt any of the following options:
   (a) To use APIs / MIOS as developed by MIOS Forum.
   (b) Replacement of existing old meters with IEC 62056 compliant meters.
   (c) To make meter suitable for open protocol (IEC-62056) by incorporating protocol converter, if feasible.
3. In order to operationalize the implementation of IEC 62056 in respect of new meters, following issues need to be addressed on priority.
   (a) Application wise standardization of parameters for various meters including tamper list may be carried out by CEA along with CPRI and NTPC in consultation with utilities. The standard parameters may then be specified by all the utilities.
   (b) Compilation of OBIS codes as per IEC 62056 for above parameters and identification of the parameters for which codes are not available and evolving codes for the same. CPRI to take necessary action in this regard.
   (c) CMRI vendors may develop CMRI having IEC 62056 compatibility for standardized parameters.
4. Ministry of power may consider constituting a committee under the Chairmanship of DG, CPRI with members from CEA, meter manufacturers and standardization body (BIS) to approve and channelize the incorporation of India specific requirement in the IEC 62056 as may be necessary at a future date.
5. Necessary action would be taken on the above points in a time bound manner to enable release of agreed common parameters at the earliest for procurement of IEC 62056 compliant meters.
6. Funds may be earmarked under R-APDRP for supporting implementation of open protocol and enhancing the facilities for testing of IEC 62056 compliant meters in the country.

4. Features of DLMS-COSEM Standards

The DLMS/COSEM specification specifies an interface model and communication protocols for data exchange with metering equipment. The interface model provides a view of the functionality of the meter as it is available at its interface(s). It uses generic building blocks to model this functionality. The model does not cover internal, implementation-specific issues. Communication protocols define how the data can accessed and transported.

The DLMS/COSEM specification follows a three-step approach as illustrated in Figure 4:

Step 1, Modelling: This covers the interface model of metering equipment and rules for data identification;

Step 2, Messaging: This covers the services for mapping the interface model to protocol data units (APDU) and the encoding of this APDUs.

Step 3, Transporting: This covers the transportation of the messages through the communication channel.

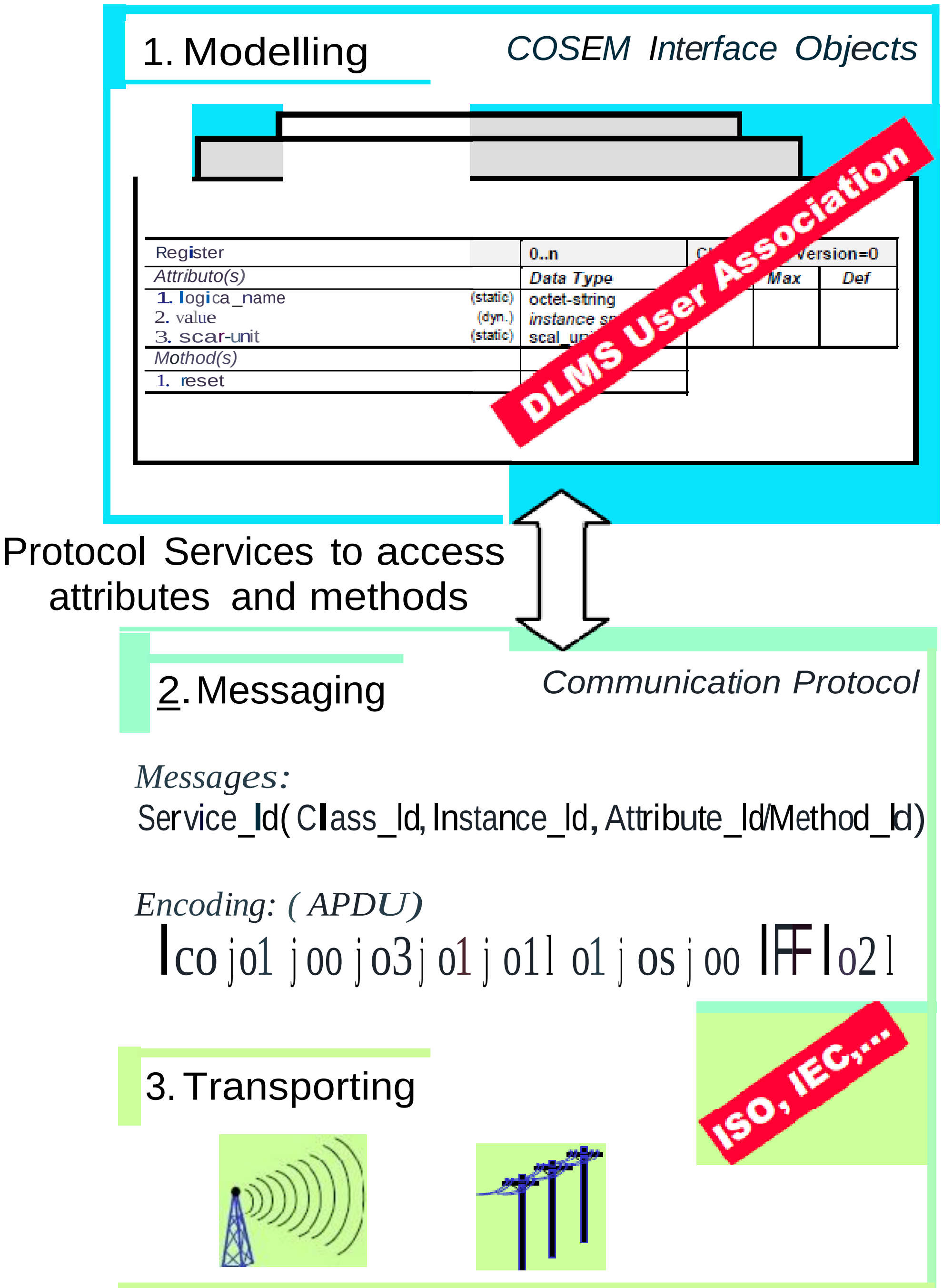

Fig. 4: The three steps approach of COSEM: Modelling-Messaging-Transporting

Step 1 is specified in the document "COSEM interface classes and the OBIS identification system" DLMS UA 1000-1. It specifies the COSEM interface classes, the OBIS identification system used to identify instances of these classes, called interface objects, and the use of interface objects for modelling the various functions of the meter.

Step 2 and 3 are specified in the document “DLMS User Association, COSEM Architecture and Protocols” DLMS UA 1000-2. It specifies communication profiles for various communication media and the protocol layers of these communication profiles. The top layer in any profile is the COSEM application layer. It provides a logical connection between the client and the server(s). It also provides the xDLMS messaging services to access attributes and methods of the COSEM interface objects. The lower, communication profile specific protocol layers transport the information.

Rules for conformance testing are specified in the document DLMS UA 1001-1 "DLMS/COSEM Conformance Test Process".

The DLMS/COSEM specification, defines the procedures for Modeling the Meter, Forming Messages and Transporting. The DLMS is well documented by the User Association (DLMS-UA) in the form of GREEN, BLUE and YELLOW books. These books narrate the above said procedures and also the testing process. In DLMS the meter is referred as Server and the Host is referred as Client.

The DLMS/COSEM specification is adopted by both the IEC and CENELEC. The three books of DLMS are brought out as standards having different Part numbers by IEC. The list is as follows:

IEC Part Number	Title
IEC 62056-21-2002	Electricity Metering – Data Exchange for meter reading, tariff and load control: Direct local data exchange.
IEC 62056-42-2002	Electricity Metering – Data Exchange for meter reading, tariff and load control: Physical layer services and procedures for connection oriented asynchronous data exchange
IEC 62056-46-2002	Electricity Metering – Data Exchange for meter reading, tariff and load control: Data link layer using HDLC protocol
IEC 62056-53-2002	Electricity Metering – Data Exchange for meter reading, tariff and load control: COSEM Application Layer
IEC 62056-61-2002	Electricity Metering – Data Exchange for meter reading, tariff and load control: OBIS Object identification system
IEC 62056-62-2002	Electricity Metering – Data Exchange for meter reading, tariff and load control: Interface Classes
IEC 62056-47-2006	Electricity Metering – Data Exchange for meter reading, tariff and load control: COSEM transport layers for IPv4 networks

The salient provisions of these Standards are as follows:

S.No	Provision	Inference
1	Meter Modeling	The Physical meter is viewed as logical units with a few functions. The functions are accessed through "interface objects" and identified through an Object Identification System (OBIS) which are unique. Interface objects contain the actual metering data. Interface objects are designed for metering data (e.g. Register object, Demand Register object, Profile object etc.)
2	Messaging	The procedure to form the packets (protocol data units) for information exchange with server (meter). The meter is accessed through interface objects. This covers the required services for mapping the interface Model.
3	Transporting	This addresses procedure to transport the messages over the communication channel. At present this standard supports Telephone line, GSM, Twisted Pair, Optical port and TCP/IP – services to access these communication medium are built in.
4	Interoperability	In a typical application (revenue metering) the DLMS meters of any make can coexist and exchange information with Host (Client) having DLMS service module. The compliance of a meter can be verified through Conformance Testing. Self-description – By this process the server (meter) provides its (capabilities) model with objects / function to the client (Host) with which it can integrate the meter with application. Unique OBIS codes for majority of the functions.
		Provision for clearly identified country-specific OBIS codes and manufacturer-specific OBIS codes. Process exists for adding new OBIS codes through the DLMS-UA
5	Security	Supports three security levels. Meter can be programmed to expose different data using different security levels. Meter data can be divided into multiple "Associations" and a different security level can be specified for each association: 1. Low level security – Passwords 2. High level security Challenges 3. Ciphering - A symmetric key algorithm AES-GCM128 has been selected, as specified in NIST SP 800-38-D. It provides authenticated encryption to xDLMS APDUs. 4. For key transport, the AES key wrap algorithm has been selected. This provides full interoperability.

6.	Open Standard	The standard documents are available for public (professionals) use. Any vendor can develop the protocol stack / drivers / modules. These can be adopted by the meter manufactures for implementing the DLMS protocol. The application (e.g. energy accounting) developers can also adopt those off the shelf soft products for development. The system integrators can put together a DLMS based system freely.
7.	Information Access	Through Interface Classes / OBIS codes / logical names / functions /attributes to read - Instantaneous values, profiles, events, clock, cumulative, demand, power quality parameters etc. The attributes are names, values, units, scalars etc. Model allows data to be identified as instantaneous values, historical values, values per tariff, values per phase etc.
8.	Legacy System	1. A cluster of existing meters with proprietary protocol can be interfaced through a Concentrator to a DLMS based Host machine running the client application. The Concentrator input will be proprietary protocol meters and output will be DLMS protocol output. 2. In built converter from proprietary to IEC 62056

5. Indian Companion Specifications of DLMS-COSEM Standards

Distribution Line Message Specification (DLMS) with functionalities of Companion Specification for Energy Metering (COSEM) based on open protocols and maintained by Device Language Message Specification User Association, DLMS UA, Geneva, in the form of four technical Reports, namely “Blue”,, “Green”, “Yellow” and “White” Books, have been adopted by IEC on regular basis in the international standards mentioned above for interoperable use of electricity meters in a data network.

The Indian Standard on “Data Exchange for Electricity Meter Reading, Tariff and Load Control - Companion Specification”, in the form of a Guide, is intended to provide a field level basis for efficient and secure transfer of electricity metering data in an open manner with judicious application of features and protocols of the International Standard. This companion specification refers to latest updates of Interface classes and OBIS codes available in 9th edition (2009) of the Blue Book of DLMS UA, This also refers to updates of procedures and services available in 7th edition (2009) of the DLMS UA Green Book under finalization. These revised Technical Reports of DLMS UA, considered as pre-standards for several parts of IEC 62056, will be adopted by IEC in due course and subsequently by BIS in adopted Indian standards being published. Till such time these books, accessible by members of DLMS User Association in India, may be referenced as IEC pre-standards.

This Specification is intended for use as companion to IS/IEC-62056 series of standards on “Electricity Metering – Data Exchange for Meter Reading, Tariff and Load Control”, adopted from various parts of IEC62056.

These generic metering data exchange standards based on DLMS/ COSEM open protocols and features, provide a coverage for structured modeling of metering functionalities as available at communication interface(s), with procedures for identification of these data objects by mapping into respective codes, and finally for direct local exchange or remote exchange of these data messages by transporting over various layers of communication channels with specified procedures and services, as applicable.

This Companion Specification provides guidelines, specifies optional DLMS / COSEM elements and outlines boundary requirements for design of such DLMS / COSEM compliant electricity meters for possible applications in Indian electricity networks. Such selections may involve:

i. COSEM interface classes, their instances, attributes and methods to be supported, Event and Status tables, identified objects, DLMS services, Communication media and protocol stacks.
ii. Requirements for Direct Local data exchange involving HHU(MRI) and remote data exchange with HOST Computer.
iii. The necessary country / project specific codes, not documented by DLMS UA, are included in Annexures for specified usage of electricity meters.

The following are outside the scope of this Specification and will be decided by user/ manufacturer/ system integrator:

i. Host computer – Metering equipment connectivity
ii. Compatible modem (Data Communication Equipment) and its requirements for chosen communication medium
iii. Values and distribution methods of secret keys

Metering functions are outside the Scope of this specification and are covered by prevailing Indian standards as applicable.

The following Indian standards which are indispensable for metering data exchange, are referenced in this companion specification:

S.No	Finalised IS Draft DOC Nos.	Title Description
1	ETD 13(6001)	Electricity metering : Data exchange for meter reading, tariff and load control Part-61: Object identification system (OBIS)
2	ETD 13(6002)	Electricity metering : Data exchange for meter reading, tariff and load control Part 62: Interface classes
3	ETD 13(6000)	Electricity metering : Data exchange for meter reading, tariff and load control Part 53: COSEM application layer

4	ETD 13(5999)	Electricity metering : Data exchange for meter reading, tariff and load control Part 46: Data link layer using HDLC protocol
5	ETD 13(5998)	Electricity metering : Data exchange for meter reading, tariff and load control Part 42: Physical layer services and procedures for connection-oriented asynchronous data exchange
6	ETD 13(5997)	Electricity metering : Data exchange for meter reading, tariff and load control Part 21: Direct local data exchange
7	IS STD-6	Electricity metering : Data exchange for meter reading, tariff and load control Part 47: COSEM transport layers for IPv4 networks
8	ETD	Electricity metering: Data exchange for meter reading, tariff and load control - Glossary of terms : related to data exchange using DLMS/COSEM
9	IS14697	ac static transformer operated watt-hour and var-hour meters, class 0.2 S, 0.5 S and 1.0 S - specification

The following International standards / Technical reports are referenced as base standards to which the Indian standards for metering data exchange and this companion Specification are related:

S.No.	International Standard/ Technical Report	Title Description
1	DLMS UA 1000-1 ed.9, 2009	Blue book, COSEM Identification System and Interface Classes
2	DLMS UA 1000-2 ed.6, 2007	Green book, DLMS/COSEM Architecture and Protocols
3	DLMS UA 1002: ed.1, 2003	White book, COSEM Glossary of Terms
4	DLMS UA 1001-1:2007 ed-3	Yellow Book, Companion Testing Process
5	IEC 62056-61 Ed 2.0 (2006-11)	Electricity metering : Data exchange for meter reading, tariff and load control Object identification system (OBIS)
6	IEC 62056-62 Ed 2.0 (2006-11)	Electricity metering : Data exchange for meter reading, tariff and load control Part 62: Interface classes
7	IEC 62056-53 Ed 2.0 (2006-12)	Electricity metering : Data exchange for meter reading, tariff and load control Part 53: COSEM application layer
8	IEC 62056-46 Ed.1.1 (2002-07)	Electricity metering : Data exchange for meter reading, tariff and load control Part 46: Data link layer using HDLC protocol
9	IEC 62056-42 Ed.1.0 (2002)	Electricity metering : Data exchange for meter reading, tariff and load control Part 42: Physical layer services and procedures for connection-oriented asynchronous data exchange

10	IEC 62056-47 Ed 1.0 (2006-11)	Electricity metering : Data exchange for meter reading, tariff and load control Part 47: COSEM transport layers for IPv4 networks
11	IEC 62056-21 Ed 1.0 (2005-08)	Electricity metering : Data exchange for meter reading, tariff and load control Part 21: Direct local data exchange
12	IEC/TR 62051-1 Ed 1.0 (2004-01)	Electricity metering : Data exchange for meter reading, tariff and load control - Glossary of terms Part 1: Terms related to data exchange with metering equipment using DLMS/COSEM
13	IEC 62051 Ed 1.0, (1999-03)	Electricity Metering – Glossary of Terms
14	NIST Special Publication 800-38D, Nov 2007	Recommendation for Block Cipher Modes of Operation: Galois/Counter Mode (GCM) and GMAC
15	NIST Federal Information Processing Standards Publication 197: Nov 2001,	Advanced Encryption Standard (AES)
16	IETF Request For Circulation (RFC) - 3394: Sept, 2002.	Advanced Encryption Standard (AES) Key Wrap Algorithm (Informative)

5.1 Architecture

The typical connectivity scheme between a meter (SERVER) and the CLIENT, considered for this specification, is shown in Fig. 5.

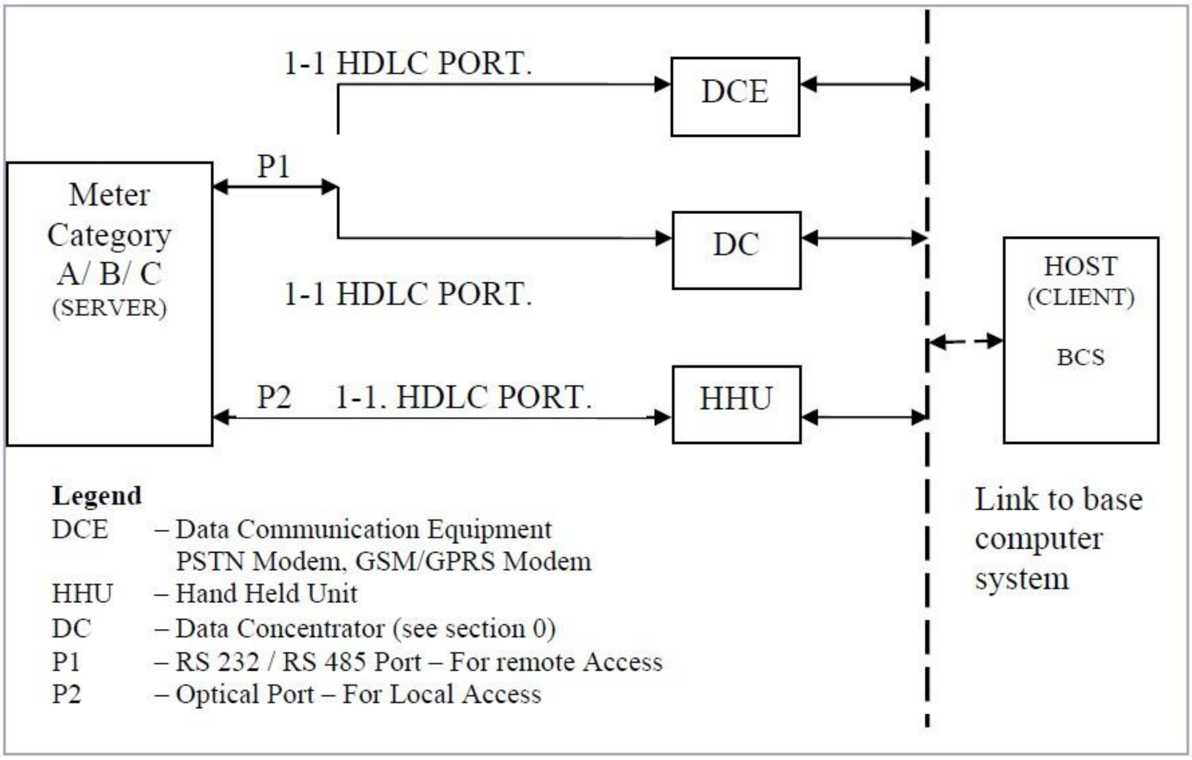

Fig. 5: Message flow connectivity scheme between METER/ SERVER and CLIENT

5.1.1 Physical Requirements

The meter (server) shall support a minimum of two ports for data communication, as given below and as per Fig. 5.

1. P1 – A hardware port compatible with RS 232 or RS 485 specifications. This shall be used for remote access from the HOST (CLIENT) or DC (CLIENT).
2. P2 – An Optical port complying with hardware specifications detailed in IS/ IEC-62056-21. This shall be used for local access from a HHU (MRI).
3. The P1 and P2 both shall support the 3-layer Connection Oriented COSEM/HDLC profile, with a minimum and default baud rate of 9600.

The optical port is not required to support any mode of IS/ IEC-62056-21, that is, mode of usage shall be direct HDLC.

5.1.2 Requirements for simultaneous operation

The meter (server) is not required to allow more than one association to be open at any one time. Optical port shall have priority when both ports are accessed simultaneously. This means that if the electrical port is connected and being accessed for data, any attempt to connect on optical port shall cause the connection on electrical port to be interrupted and the optical connection processed after sending “DM” (Disconnected Mode) message to HOST. Any further attempts to communicate on electrical port while the optical port is being used shall be returned with a “DM” code. This is an indication to the host that the meter is temporarily busy.

5.2 Logical Structure of Meters

The meter represents one physical device as mentioned in IS/ IEC 62056-62 clause 4.5. The physical device (meter) hosts one logical device as mentioned in IS/ IEC 62056-62 clause 4.5, which is the Management logical device. This has SAP (Service Access Point) address 1, as mandated in IS/ IEC 62056-53. The physical device address (lower HDLC address) shall also be set to a default value of “1” on supply and the actual communication address shall be programmed on installation.

The meter shall support the Logical Name (LN) referencing mechanism as defined in IS/ IEC 62056-62 Annex C.1. Short name referencing as defined in IS/ IEC 62056-62 Annex C.2 is not required to be supported.

The meter shall support three associations in the Management Logical Device

a. Public Client association (PC)
b. Meter Reader association (MR)
c. Utility Settings association (US)

5.3 Metering Parameters with Data Identifiers

Three categories of electricity meters have been selected for compiling comprehensive lists of metering parameters with their data identifiers as required for data networks in India for COSEM procedures and services. The relevant documents are listed in Table 1 below:

Sr No	Technical Report	Title Description
1	CEA	Installation and Operation of Meters, Regulation 2006.
2	CPRI	Standardization of Metering Parameters, April 2009
3	CBIP Publication 304	Manual on Standardization of AC Static Electrical Energy Meters (for electrical energy and tariff related parameter terminologies)

DLMS/ COSEM compliant interactive meters can be treated as servers in a data network with end devices as clients. Table 2 lists the server categories with metering nomenclatures and Annexure references.

Server Category	Metering Nomenclature / Purpose	Annexure Reference No.
A	Energy Accounting and Audit Metering	A1, A2, A5,A6
B	Boundary / Bank / Ring / ABT Metering	A1, A3, A5,A6
C	HV (PT / CT) and LV (CT) consumer Metering	A1, A4, A5,A6

1. **Category A Meter** – This meter is identified for use at sub-station feeders and Distribution Transformer Centers. The parameters listed for this category is for “Energy Accounting and Audit” purposes.

2. **Category B Meter** – This meter is identified for use at Meter Banks and Network boundaries. The parameters listed for this category is for import / export of energy. This meter is also suitable for Availability Based Tariff (ABT) regime.

3. **Category C Meter** – This meter is identified for use at HV (PT and CT operated) and LV (CT operated) consumers. The parameters listed for this category is for consumers who draw energy from the grid. For consumers who also supply energy to grid, the category B Meter is recommended.

Module -B
Automatic Meter Reading

1. Introduction

Automated Meter Reading (AMR) is a technology that permits the automatic collection of data from energy-metering devices and transfers that data to a central database for analysis and billing purposes. The measurement and collection system is commonly referred to as advanced metering infrastructure (AMI) and is used in the electric, natural gas and water industries around the world. The choice to automate key processes has two broad benefits: reduced costs for the utility and improved quality of service for commercial, industrial and residential customers.

Automated meter reading can be carried out in many ways. One of the intermediate solutions that customers may have seen is reading meter using palm devices, hand held computer, wireless drive by systems etc. So a meter reader need not look at the meter to read it. He can pass by the customer‟s place and have a meter reading on his hand held device. These types of metering system is certainly an Automatic meter reading system but does not constitute an elaborate mechanism for effective automatic meter reading system. The effectiveness in automatic metering system can only be established if the ground for demand side management of energy is laid on the daily basis and is scalable as per the hierarchy of customer and participating business entities. This mean that meter reading activity cannot be treated as an event that takes place once a month or twice a month only for generating bills. Then, this means that meter has to be read as often as possible and whenever required, the meter data should be made available for analysis and management purpose. The only compelling mechanism that can lead us with metering data on the desktop is by having an active network of meter. Thus one of the prime requisites for carrying out demand side management is to have metering devices on network. Perhaps this agenda of having network is only a broader idea and shall require real engineering to be carried on the product to make it a viable proposition considering other key challenges posed by the meter types and power system hierarchy. Creating a cost effective network itself is a big challenge for effective AMR. Architecting the networking and sub-networking sphere of this domain for more challenges like bringing different types of meter on to network and also the topological distribution of meters. Topological distribution of meter poses a big challenge on choosing medium of communication for bringing metering system onto network. Cost effectiveness of bringing meter onto network when meter poses a challenge from topological reason is another issue to be considered. And if this is does not turn out to be an effective proposition, then how data correction is incorporated in the back end software becomes a tactical issue.

The other challenge posed is related to the data transmission from the meter. Different types of customer have different type of metering systems. Say for example, a residential customer has a metering system which is 1 phase and 3 phase type and meter reads only KWhr as a parameter for energy consumption and where as an industrial consumer have a metering information consisting of KWhr and maximum demand, and some of them trivectors meters installed for carrying out metering for all the three energy vectors of importance. Apart from this, meter needs a periodic check as well from the remote location and should also have theft prevention mechanism along with the encryption. If we consolidate the above mentioned challenges, then it broadly means that AMR on the meter side should have:

1. A Choice of communication interface that can latch to network
2. An interface with the meters of different type and is scalable.
3. A standard interface that can cater to vast class of meters in the field.

Considering the issues at the metering layer, communication system layer, intermediate communication devices are through, then the issue that remains is building up a data acquisition system and data storage system, and then building up service provisioning on the data acquired.

2. Automated Meter Data Acquisition

Automatic Meter Data Acquisition is generally regarded as the reading of a utility meter by a means that does not require physical access or visual inspection of the meter. A typical meter data acquisition system has several main components: meter, meter interface unit (MIU), a communications network and host computer. Normally, within an AMR system, the meter data is passed from the meter to an MIU, which may be external to the meter or integrated within the body of the meter. In addition to the meter data, other pertinent information may be stored within the MIU, such as any tamper or alarm conditions. This device forms the interface between the meter and the communications network.

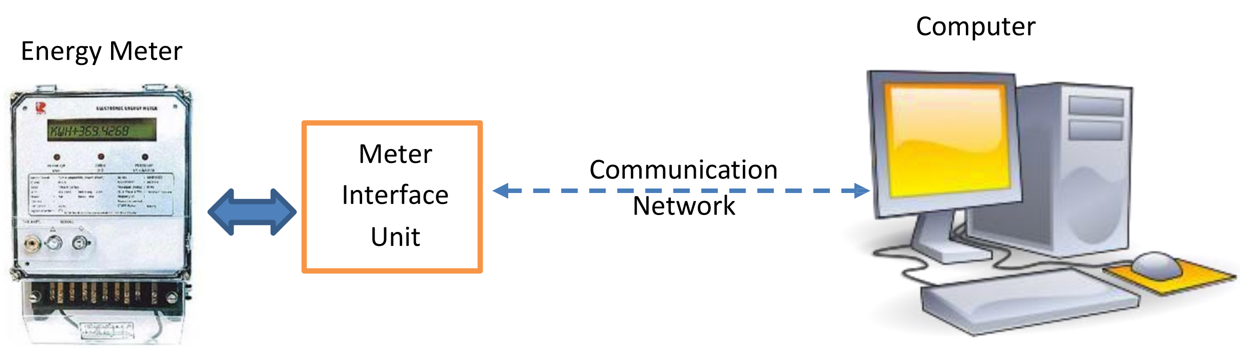

Fig. Automated Meter Data Acquisition

2.1. Various means of Communication for AMR

Many communications networks have been used for AMR, including modulated radio frequencies (RF), telephone lines, or the electric power line itself. Depending on the network used, information from the MIU may be retrieved and stored in intermediate nodes or delivered directly to the utility. In the case of an RF network this may be a hand-held receiver, a mobile unit, such as a van, or a node on a fixed network. The transfer of the meter data from the network to the utility may be instantaneous or stored for later transmission to the utility host computer. Often, on a fixed network, the data from the MIU is transmitted via a wide area network (WAN) back to the host computer. The WAN may be any variety of data networks, including; private data services or public data networks. Once the data is resident within the utility, the meter and other retrieved information can then be shared with other points on the system, including a customer service representative's PC or the central billing computer.

As mentioned, the meter data from the MIU can be transmitted over a variety of communications media including telephone, power lines, satellite, cable, and radio frequency (RF). Each of these methods has advantages and disadvantages as well as specific suitability. Many utilities who have implemented AMR have found that no single technology is universally available or viable for all their AMR needs and that often multiple communication technologies are needed to optimize a complete system.

Following are various communication technologies in use for AMR applications:

1) **Mobile radio systems**: This technology is widely known as Walk-by or Drive by RF systems. The system retrieves the meter data by means of a collection device moving along the meter-reading route, either in a vehicle or being carried by a meter reader on foot.
2) **Mobile phone network or fixed networks**: This technology utilizes public and/or private communication networks such as mobile phone network (GSM/GPRS). The data collection assets are not mobile and may be part of a public or private network, or a mixture of both.
3) **Power Line Communication (PLC):** This technology utilizes the power lines of the local electric utility to retrieve the data from the endpoint to the substation, and then utilizes various communication technologies to convey the data to the central data collection point.
4) **Hybrid systems**: Utility has a number of choices on how the meters are read – Mobile radio frequency (handheld, vehicle-based) or fixed network frequency or a combination of technologies using PLC. The utility can mix and match these options based on the specific application. Future AMR systems are predicted to follow this trend.

2.2. Network topologies in use to acquire meter data

In AMR system, the communication networks used are either single stage communication from meter to computer or hybrid communication technologies. Only long range communication radio networks such as GSM can be used for single stage communication from meter directly to central data center.

2.2.1 GSM Based Communication

In GSM based communication system, an existing cellular network is utilized for data transportation and requires no additional equipment or software, resulting in a significant savings in both time and capital. The GSM/GPRS cellular technology utilizes an encryption technique to prevent an outside source from receiving the transmitted data hence ensure security of the meter data. The cellular network provides full two-way communications, allowing scheduled reads, demand reads, alarm and event reporting, power outage reporting and power restoration reporting.

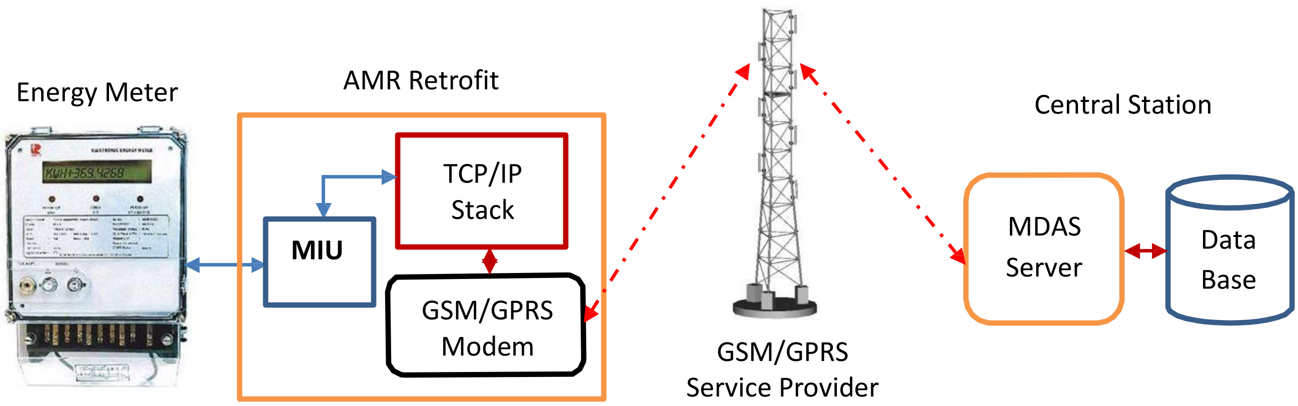

Fig. GSM Communication for AMR

In GSM based communication implementation for meter data acquisition, there are two different communication modes are in use which are **inbound dialing** and **outbound dialing**. In the inbound mode, the GSM modem will initiate communication to send reading or event data to the data acquisition server. It will again invoke manufacturer specific meter commands to collect data from the meter reading and tamper registers. In the outbound mode, the modem passes the commands sent by the data acquisition server to the meter and directs the meter response as-is back to the server. The meter manufacturer specific APIs running on the server will send the necessary commands to collect the meter data. The server holds the APIs for enabling outbound dialing to various makes of meters. Meter data acquisition outbound scheduler software schedules automatic dial out to respective meter-end modems. Raw reading/tamper data retrieved is first stored in flat files. This also applies to the data obtained from inbound dialing or downloaded from MRIs. The data analytics module then validates the raw data and stores it in the Oracle Database so that it can be used for further analysis.

GPRS network can also be used for meter data acquisition in inbound and outbound modes. In inbound mode, GPRS modem will establish a TCP socket connection to the server (having static public IP). Once the connection established, server will take over the communication by invoking APIs and sending commands to server on transparent GPRS data channel. The response received from server is then captured by API and saved in raw meter data file. Once the data captured it will converted to desired xml data through another API running in batch mode. The biggest advantage of using GPRS network is that it doesn‟t require multiple modem hardware at the server side unlike dialing mode. Server can handle multiple TCP socket connections from meters without adding any hardware cost. The GPRS network can also be used in VPN or outbound mode where all modems in the field will be having a static network assigned IP address. Server can contact any modem based on the schedule procedure and establish a communication link for meter data acquisition.

2.2.2 Hybrid Communication

Owing to the challenges involved in making AMR technology effective and viable at economical cost, many times the combination of multiple communication technologies are used. The hybrid communication technology has two stages of communication in AMR System

- **Meters and Data Concentrator Unit (DCU)**: Communication channel used between meters and DCU is Power Line.
- **DCU and Host Central Station (HCS):** Communication channel used between DCU and HCS is the standard GSM, CDMA, RF or PSTN Network.

The power line communication (PLC) has many advantages for its use at low voltage level at consumer end. It is most economically and viable technology for transferring Meter data to DCU. It uses the technique of communicating the data over existing electrical lines which carry LT power to the site. PLC communicating devices employs an ASIC, which accepts digital data & converts it into FSK modulation and transmits it over the power line by sensing a zero crossing of 220V sine wave. Typical frequency used for frequency modulation is 132KHz.

2.2.3 AMR System: Data Pooling Approach

The purpose of this approach of automatic meter reading is to provide low cost AMR facilities in the system. It has all the features of AMR system with the innovative data pooling strategy to bring cost down for the end customer. In this strategy the complexities are kept away from the end customer and are sequentially brought up into different layer of the product architecture like forwarder and data concentrator computer and Data center, whose cost gets distributed. The system comprises of a Meter Interface Device, Data Forwarder (DF), and Data Concentrator computer (DCC) and Host system. Meter interface unit just keeps track of meter reading to which it is fitted into. Meter interface has a modem of the type PLC, wireless-FSK, PSTN type for providing the connectivity to Power line or wireless or Phone line. Each MIU is connected to a forwarder that connects meter interface unit to Data concentrator computer. Each data concentrator is connected to Host computer of Data center (HCDC).

i) **Meter Interface unit:** MIU comprises of PCB/device retrofitted in pulse energy meter. The MIU comprises of the following major components:

(a) A modem module (any one of PLC or PSTN or FSK/SS wireless).
(b) A power line coupler for 230 V.
(c) Micro controller with external EEPROM, which has a communication port. A unique silicon ID is fused in this EEPROM. Through hand held device meter number, initial meter reading and meter constants are programmed.
(d) A power supplies converting AC to DC and is used for feeding each sub modules.

Meter interface unit has two major component blocks. One is meter interface side and other is modem. Meter interface side consists of a micro controller and data memory. Meter interface side sends command to the meter, gets the response and stores it in memory. It also implements a protocol for two-way communication to report the meter reading and meter activity to the DCC through modem. So meter side interface implements protocol for two-way communication to modem and to data concentrator computer. The call to MIU is always initiated by DCC through forwarder. To meet the varying requirement of topological distribution of meters, broader consumption level, the meter interface component can be categorized. This provides a great deal of flexibility and justification of doing AMR for large utilities. The components that are required to interface meter and provides the physical layer communication to AMR systems can be categorized as follows:

S.No	Component	Connectivity	Purpose
1.	MIU	PSTN	For high-end customers like C&I type.
2.	MIU	PLC	Suitable for both medium and high end customer. Deployment should also consider topological issues
3.	MIU	WL(network based)	Suitable for very high end customer
4.	MIU	WL (very short range)	Medium level customer where in sub grouping of MIU is possible.
5.	MI	Grouped in PLC	Very low end customer and where meters are nearby in high density
6.	MI	Grouped in short range WL	Lower medium and very low end customers

ii) **Data Forwarder:** DF comprises of the following major components:

(a) A PLC modem module.

(b) A low-end microprocessor system like ARM7TDMI with 1 MB of RAM, 24K of EEPROM with two serial ports. Silicon ID for this device is fused in EEPROM.
(c) A wireless spread spectrum modem module with serial interface is integrated along with microprocessor-based system.
(d) A power supply to feed all these three major units.
(e) A weather proof encasing for all these.

DF is a device that forwards the data coming from DCC to the MIU or data coming from MIU to DCC. It also acts like a router for other DF units connected to different set of MIUs which may not be accessible to DCC directly. DCC makes request to DF first, then receives meter data through Wireless Spread Spectrum module. The data received by DF from DCC is analyzed either for routing to other DF or send on to PLC modem to obtain meter related information. The response of the meter is also reported back to DCC through DF. So, a DF is a device consisting of PLC-LV modem on one side (on the meter side and PLC-MV) and WL-SS modem on other side. DF is a router at DF layer as well. Thus DCC can approach remote DF through intermediate DF within reach of DCC. There are three types of DF and is listed below along with specific purpose.

S.No	Components	Connectivity (I/O)	Purpose
1.	DF	PLC(LV)-PLC(MV)	Creating PLC network and by passing transformer.
2.	DF	PLC(LV)-WL-SS	Creating a hybrid network with connectivity wireless and PLC
3.	DF	WL-SR-WL-SS	To supplement lower medium and very low level consumer. Making it cost effective

iii) **Data Concentrator Computer:** DCC comprise of stand-alone computer. It has following major components:
(a) A stand-alone computer may be with low-end configuration, networking ports and storing capacity on hard disk drive etc.
(b) A modem module with interface to computer through serial port.
(c) A PLC modem module with connectivity on port of the computer.
(d) A real time clock on the motherboard of computer.
(e) PSTN modem connectivity with computer.

The main function of this unit is to accumulate the data from the various makes of meters and push the accumulated information on the Data center network through host computer. It temporarily stores the information based on the metering condition and forwards it to Host unit. DCC has a connectivity with PLC-MV, PLC-LV, WL-SS, GSM, PSTN-IB, OB modems thus acting as device which is collecting data from all possible connectivity on which instrument is hooked up. Along with HOST functionality, it also implements standard protocol at higher layer and integrate with DC.

iv) **Host computer of Data center**: HCDC comprises of host computer along with network of computers. It has following major components:
   a) A high-end computer, which is connected to DCC on one side and is on network of computers for managing data center.
   b) Host system is a high-end system consisting of computer system with large RAM and HDD capacity.
   c) Host is connected to the network of computers through Ethernet or wireless LAN network.

Host computer"s main function is to set up DCC parameter related to metering process, managing connectivity related to meters and DF. All the new accounts setup related to meters, DF and network is carried out from this unit. Then acquired data from DCU is pushed on the data center network. Host is an active part of data center but does a dedicated job of setting and managing data concentrator computer. One end of HC is connected through DNP protocol which integrates this with different type of information sub systems of Utilities and Generating subsystems.

v) **Data Center**: DC is a unit which manages database of metered data and also provides various services based on the data to utilities, end customer, power companies, and maintenance companies etc.

2.2.4 ZigBee based AMR System

ZigBee is a new wireless networking technology using small, low-power digital radios based on the IEEE 802.15.4 standard for wireless personal area networks (WPANs). It has recently been developed for remote metering application and that made ZigBee the latest alternative for AMR. A ZigBee-based AMR system acquires electricity consumption data from a meter automatically. Data is transmitted through a wireless mesh network infrastructure to a server, which can be located distance away. Each ZigBee network is identified by 16-bit network ID. The network will contain following three types of nodes/devices in the system:

i) **GSM-ZigBee Coordinator (GZC):** GZC coordinates the wireless energy meter network nodes and act as a bridge between GSM communication and 2.4 GHz wireless ZigBee communication. It is responsible for selecting the 2.4 GHz wireless channel and Network ID. The GZC starts a new network on power up. Once it has started a network, the GZC can allow energy meter routers and energy meter nodes to join the ZigBee network. The GZC can transmit and receive RF data transmissions, and it can assist in routing data through the mesh network. It acts as a bridge between remote server and energy meters for all communications.

Fig. 1 shows the functional block diagram of GZC unit. It is just a communication bridge and contains no energy meter module.

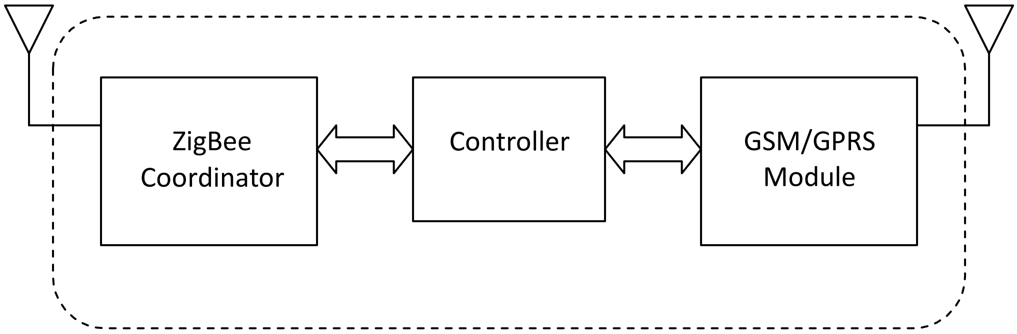

Fig. : Functional Block diagram of GZC

ii) **Energy Meter Router (EMR):** An Energy Meter Router must join an Energy Meter ZigBee Network before it can operate. After joining a ZigBee network, the router can allow other routers and end devices to join the network. The router can also transmit and receive RF data, and it can route data packets through the network. It is node with energy meter and communication and can be installed in user premises. Fig. shows the functional block diagram of EMR unit.

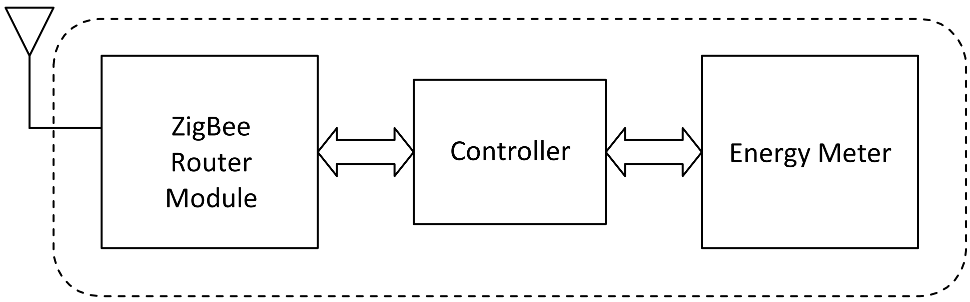

Fig. : Functional Block diagram of EMR

iii) **Energy Meter Node (EMN)**: Energy meter node collect all energy monitoring parameters from the user premises. This node must join an Energy meter zigbee network, similar to a router. The EMN, however, cannot allow other devices to join the network, nor can it assist in routing data through the network. An EMN can transmit or receive RF data transmissions. The EMR or GZC that allowed the EMN device to join and that manages RF data on behalf of the EMN is known as the EMN"s parent. The EMN device is considered a child of its parent. It is similar to EMR except the zigbee firmware. An EMR or GMZ can only allow up to 8 EMN devices to directly join to it.

EMZ - Network

Energy meter ZigBee network is a network of wirelessly interconnected energy meter nodes and GSM-ZigBee coordinator. All data packets are addressed using both device and application layer addressing fields. Data can be sent as a broadcast, or unicast transmission. EMZ-Net employs mesh routing to establish a route between the source device and the destination. Mesh routing allows data packets to traverse multiple nodes (hops) in a network to route data from a source to a destination. EMR and GZC can participate in establishing routes between source and destination devices using a process called route discovery. The Network topology is shown in Fig. .

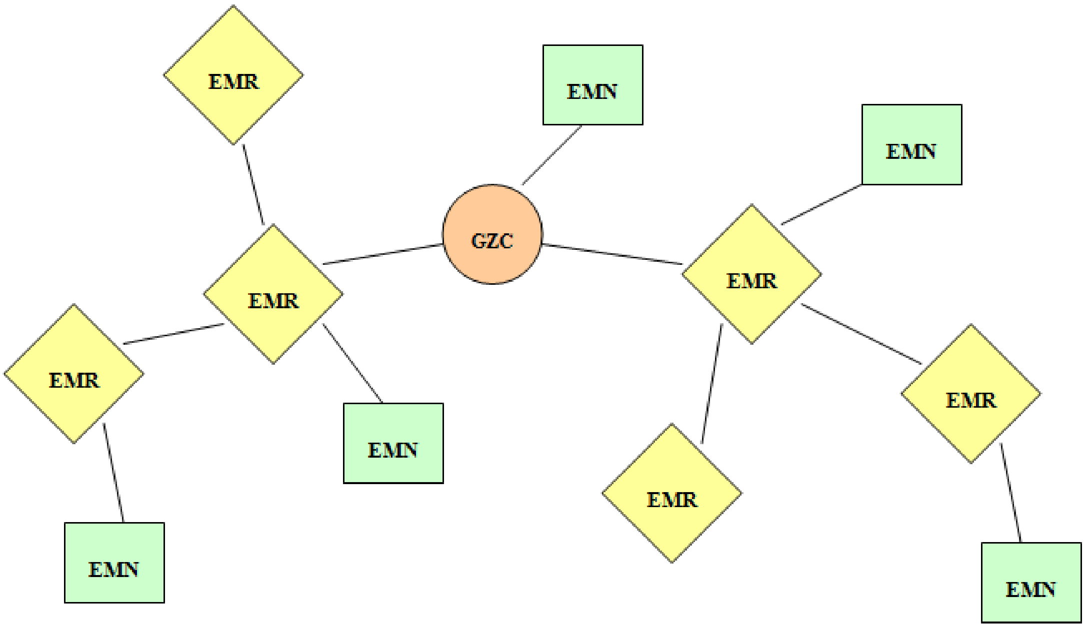

Fig. : EMZ-Net Topology

One GZC can connect to 8 EMR or EMN devices. Each EMR again connect to 8 EMR or EMN devices.

2.3. Software Application for Meter Data Acquisition (AMR)

The main objective of Meter Data Acquisition Software (MDAS) application is to acquire meter data from System and Select consumer meters automatically from remote avoiding any human intervention, Monitor important distribution parameters, use meter data for accurate billing purposes and generate exceptions and MIS reports for proper planning, monitoring, decision support and taking corrective actions on the business activities by the management.

The above objective can be achieved by providing an Automatic Meter Reading (AMR) based Data Logging System using any of the available Communication Technologies like GSM, GPRS, EDGE, CDMA, PSTN or Low Power Radio covering all the Feeder Meter, DT Meters and select Consumer Meters in the entire Utility area.

The MDAS software shall meet broad functionalities and requirements of AMR based Data Logging System at Substations, Sub division and other offices in the entire utility area to acquire & store data of Energy Meters of various makes installed at 33/11 KV Feeders, Distribution Transformers, HT / select LT consumer ends.

The substation Data logger PC shall acquire data from Feeder Meters and will transmit the same to Sub division office server through a GSM/GPRS/EDGE/CDMA/PSTN/LPR Modem, whereas the Sub division office Data Acquisition server will acquire data directly from all Distribution Transformers as well as HT/select LT Consumers through GSM/GPRS/EDGE/CDMA/LPR Modems.

The Data acquisition servers at all sub division offices shall push the entire meter data to central data center on incremental basis during off-peak period on daily basis through MPLS/VPN based WAN network for data aggregation, analysis and generation of MIS report as per requirement of the utility.

The substation meters are fitted with RS 485 ports, whereas meters at DT & select consumer locations fitted with RS 232 ports. The meters at substations are generally modbus compliant. However, the solution provided shall be compatible with future meters also, which may be introduced in Indian market complying with DLMS/ COSEM / IEC-62056 /ANSI C-12.19 / IEEE P 1377 Standards. For solving the interoperability issue of different make / model of Meters installed presently in different utilities, Utility shall provide meter protocol and memory map of the meters installed in their area. As most of the meters provided presently are Modbus compliant, Modbus/TCP shall be the preferred mode of communication.

The Data Logging system will provide continuous on line monitoring and logging of following parameters in respect of all incoming and outgoing feeders, Distribution Transformers and consumers on real time basis :

i) Voltage, Phase to Phase and Phase to Neutral
ii) Current on each phase
iii) Power factor
iv) Frequency
v) Power - Active / reactive / Apparent

vi) Energy – Active, Reactive and Apparent

The system will provide continuous on line monitoring and logging of above mentioned parameters and capability to generate Spread Sheets and MIS report as below:

i) System outage / downtime feeder wise.
ii) Energy balancing at sub stations.
iii) Daily peak loads feeder / transformer wise.
iv) Peak Load of the Station.
v) Bus bar profile.
vi) Daily Log sheets & any other forms / reports as required by the Utility

2.3.1. System features

i) ***Provision to collect and manage meter data***: The system shall collects and comprehensively manages meter data from system (utility network) meters and select customer meters using MODBUS/DLMS/COSEM/IEC/ANSI/IEEE compliant protocol. As most of the meters presently are Modbus compliant, Modbus/TCP shall be the preferred mode of communication.

ii) ***Remote capturing of meter data from system & select consumer meters***: The MDAS system shall captures the meter data remotely from all the meters at 33 KV & 11 KV Feeders, Distribution Transformers and HT/select LT Consumers for sending it directly to the remote collection center i.e. sub division office and data center.

iii) ***Provision of communication media***: The system shall provide interface for GSM/GPRS/EDGE/CDMA/PSTN/LPR or any other suitable Communication technology between Meters located at Distribution transformer/HT/LT consumers and Sub division office. The system shall also provide for above mentioned or any other suitable communication technology from Data Logger PC located at substation to the Sub division Office.

iv) ***Optimal utilization of meter data***: A system that optimally utilizes meter data for distribution management and billing.

v) ***Provision of a decision support system***: The MDAS software should have a decision-support system for distribution operations, asset management and planning actions, e.g. Peak load monitoring. It will help in finalizing the requirements for creation of additional electrical network element or upgradation of existing electrical network element to meet the increased demand / load growth, Power factor monitoring shall help in capacitor placement requirement, voltage monitoring shall help in identifying low voltage areas for network up-gradation, data captured on imbalance between phases for DT, substation and 3 phase consumer meters can be used to increase reliability/plan load balancing jobs / advise customer to transfer loads between phases etc.

vi) ***Identification of poorly performing areas***: The system shall pinpoints poorly performing areas in the sub transmission/ distribution network, based upon the technical parameters, such as area wise distribution losses, theft, outages, overloaded circuits/equipment, voltage imbalance, reliability indices, power quality etc.

vii) ***Helping in network upgrade actions***: A system that aids decision making on network upgrade actions by leveraging of historical meter data to calculate area-wise load growth, equipment wise, downtime/outage statistics, seasonal effects and usage pattern for long term and short term planning.

viii) ***Enabling health and performance monitoring of assets***: A system that enables „health" and performance-monitoring and management of important system assets (feeders/ transformers).

ix) ***Detection of HV/DTR outages***: A system that enables quicker, „event-driven" detection of HV/DTR outages thereby improving reliability indices and customer satisfaction.

x) ***Monitoring of customer performances***: A system that enables monitoring of customer "performance", e.g. contract demand violation, peak load violation, tamper counts, average power factor etc. The system should also have provisions to cover usage patterns to solve high consumption complaints, facilitate calculation of assessed readings for stopped meter cases, detect low consumption cases by comparing average historical consumption with actual consumption.

xi) ***Enabling dispatch of event notifications***: A system that enables dispatching of event notifications to targeted recipients for faster field response and decision making.

2.3.2. System Architecture:

i. ***Provision of an integrated software system to meet the functionality of AMR***: An integrated software system should be provided to meet the following Functional requirements spanning Automated Meter Reading :-

a) Real Time data acquisition from Meters
b) Historical data acquisition from Meters
c) Supervisory function i.e. processing, monitoring, analysis and diagnostics
d) Data exchange
e) Storage of data
f) Report generation and reporting
g) Facility for user defined forms and reports e.g. calculation of Feeder/ DT performance statistics
h) Facility for time synchronizing
i) Alarm list
j) Event list
k) Limit value violations

ii. ***Flexible deployment /implementation of software system***: The software system deployment/implementation should be flexible. The deployment may include installing the software at various locations like substations, sub divisions and data center. The system architecture will be modular so that only the required modules need to be installed at any given location. (e.g. installation at substation computer may have modules like data acquisition or network topology management. But data aggregation/analysis modules may be installed at sub division offices, data center etc. as per the requirement of utility).

iii. ***Menu driven software system***: The software shall be menu driven functions for automatic data capturing, periodic data uploading etc.

iv. ***Provision for local / remote data collection***: The software shall have option for data collection from meters connected locally or that are located in remote locations, through modem communication.

v. ***Facility for Web based front end***: Software shall have web based front end.

vi. ***Provision for data validation at both ends***: The software shall ensure data validation at both ends e.g. at the substation end before transmission and Sub division office after reception to eliminate possibility of garbage data. The system at Sub division office should apply comprehensive data validation before accepting and using meter data.

vii. ***Provision for flexibility, user friendly and scalability***: The software system shall be flexible in terms of System & Application software, user friendly and scalable upwards and downwards.

viii. ***Software system with robust architecture, high availability and reliability***: The software should be based on a robust architecture model / framework (such as Microsoft‟s .NET or J2EE framework) that is highly scalable/available/reliable, gives good performance, and offers distributed computing.

ix. ***N-tier design methodology***: The software would be designed with multi-tier (Ntier) design methodology. It should have distinct tiers representing the client/ business/database layers etc.

   a) **Client tier**: The client tier will be the interface of the software with the utility‟s operations/ dashboard user. The client tier will provide all the user interfaces for the operational and supervisory activities involved in meter data acquisition, processing and analysis.

   b) **Business logic tier**: The business logic tier would service the requests made by the client tier. These requests could be automated, based on user-defined schedules or on demand from the user.

   c) **Database tier**: The database tier should comprise an RDBMS that should be designed to be able to maintain the relationships between meter and network assets, network topology, user privileges, service points, customer accounts and other entities.

x. ***Automatic workflow process from data acquisition to analysis***: Normal workflow processes from meter data acquisition to analysis would be as automated as possible; for example user intervention would be sought only for data editing or verification decisions.

xi. ***Maintenance of time stamped database***: The database should also maintain a time-series repository that stores the data collected and processed from meters, including interval usage data, event logs and outage history, as well as derived data such as aggregations and asset performance indicators like load factor and load duration curves.

xii. ***Optimal designing of database***: The database tier should be optimally designed to exploit both normalized as well as multidimensional data models.

xiii. ***Provision of OLTP and OLAP models***: Both OLTP (Online Transaction Processing) and OLAP (Online Analytical Processing) models should be exploited for ensuring performance and scalability.

2.3.3. Features of Data Logging System at Substation:

i. ***Data collection on a common data structure***: Software shall be capable of collecting data on a common data structure / format from Feeder meters of various manufacturers installed in the Substation. The data logging software package should be able to integrate, extract and analyze data of different make of Meters.

ii. ***Data collection at substation via RS485/ RS232 data converters***: The software at Substation will have the ability to perform remote data acquisition from Meters using RS485 / RS232 port Converters.

iii. ***Main areas of data collection***: The software will in general collect the following data from the meter -
   a) Billing Data
   b) Load survey profiles
   c) Tamper data
   d) Date and time of collection of data
   e) Instantaneous parameters at the time of collection

iv. ***Typical list of data acquisition from the Meters***: A typical list of data acquisition from the Meters has been mentioned below :
   a) Acquire real time instantaneous data like voltage, current frequency, power factor, active power, reactive power etc. at the specified regular intervals (15 minutes-30 minutes as per meter specification) for online local monitoring at substation level.
   b) Acquire stored historical values of data at regular interval with power consumptions, accumulated energy, accumulated power, maximum demand and other parameters.
   c) Acquire real values of specified parameters on demand.
   d) Synchronize date and time of all meters.

v. ***Provision of generating critical events***: Software shall be able to provide details of critical events (e.g. No communication with Meter, Power failure etc.) and necessary provision should exists to report the correct event to user.

vi. ***Provision of manual entry of data in case of meter change***: Software shall have facility to enter manual readings & associated data for taking care of meter change on feeder, but only with appropriate user identification, security and audit trail.

vii. ***Seamless transfer of data even in case of meter change***: Software shall show and transfer data seamlessly even in case of meter change. An indication of meter change shall be available.

viii. ***Storage of meter data at substation***: Software will acquire and store the Meter data in the Data logger at substation in it‟s local database The Subdivision office server will poll the substation data and store in it‟s local database at Subdivision server.

ix. ***Mode of data transfer from substation to Subdivision office***: Normally the data transfer from Substation data logging system to Sub division office will be over GSM/GPRS/EDGE/CDMA/PSTN/LPR by dialing from either end at some specified interval of time.

x. ***Facility for back up and restoration of data***: Facility for taking backup & restore of data collected at substation shall be provided in software.

xi. ***Administrator facility***: Substation software shall provide administrator facility to decide the storage of data on local computer. However, the substation computer shall have a storage capacity of Meter data of at least 90 days.

2.3.4. **Features of Data Logging System at Subdivision Office:**

i. ***Periodicity of data collection***: System shall be capable of collecting data from all the HT consumers at least every one Hour and from all the Distribution Transformers at least once in 24 Hours. The substation data shall also be polled at least once in 24 Hours. Further, the system shall be designed and shall have provisions for inclusion of new Consumers and Assets in future and shall provide additional spare capacity to cater 7.5% per annum growth over and above the actual requirement at site on account of the future provisions.

ii. ***Functionality of Sub division office Data acquisition software***: The Data acquisition software at Sub division office must have the following functions :

a) Data Collection: It shall collect data from the remote Data logger systems installed at the substations and store in its local Database. It shall also collect Meter data directly from DTs and HT/select LT consumers through GSM/GPRS/EDGE/CDMA/PSTN/LPR Modems and store in its local database.
b) Data Processing: It shall use data from the database to create reports, charts and spread sheets.
c) Data transfer to data center : It shall be able to transmit entire incremental meter data to data center and shall reside in the Metering module for further aggregation, analysis and MIS generation as per request from various utility offices.
d) Messaging : Via GSM/GPRS/EDGE/CDMA
e) Program Generator : It shall have editors and configuration software.
f) Facility to communicate with multiple clients simultaneously through multiple communication lines.
g) The communication shall be scalable and configurable to various media like PSTN, CDMA, GSM, GPRS, EDGE or LPR Modem etc.

iii. ***Availability of sufficient storage capacity***: The system shall have sufficient memory capacity for storing every Analog, Digital and Accumulator data of all connected remote Data loggers in the substations as well as all DTs and Consumer data for a period of at least one year.

iv. ***Generation of DT wise, Feeder wise and Substation wise data base***: The software shall provide DT wise, Feeder wise and Substation wise data for generating summary reports, statistical data, performance indices etc. in user defined forms.

v. ***Ability of software to integrate, extract and analyze data of different make of Meters***: Software shall be capable of collecting data on a common data structure / format from DT meters and HT/select LT consumers of various manufacturers. The data logging software package should be able to integrate, extract and analyze data of different make of Meters.

vi. ***Manual/ automatic mode of data transmission***: There should be provision for manually dialing the modems connected to the DT and Consumer meters or by configuring the software to collect the data from meters automatically with the help of Scheduler feature provided for auto dialing.

vii. ***Viewing / exporting of collected data***: The collected data can be viewed in the form of customized reports. User can take print outs of these reports, export the data into spreadsheets, or convert the data in the form of flat file.

viii. ***Mode of transfer of Meter data***: The data file will be transferred from the substations to sub division office server in one of the following possible methods:-

   a) Data retrieval by sub division office from sub-station: Data acquisition software at sub division office may dial up the substation software over PSTN/GSM/GPRS/EDGE/ CDMA/Low power radio at some specified intervals and retrieve the data file.

   b) Data transfer from sub-station to sub division office: Substation software may dial up sub division office data logger system over PSTN/ GSM/GPRS/EDGE/CDMA or Low power radio at some specified interval and transfer the data file.

ix. ***Facility for archiving, deletion, backup & restoration of the data***: Facility for archiving, deletion and taking backup & restore of entire or part of the data collected at Sub division office shall be provided in Software.

2.3.5. Meter Data Acquisition – Software Requirements:

i. ***Configurable data collection engine for meters of different make***: The Data collection engine of the Data logging software shall be configurable for Meter of different make and shall have the ability to perform remote data acquisition from system and customer meters.

ii. ***Enabling of data acquisition from different AMR configuration***: The software will enable data acquisition from different AMR configuration schemes (based on location and selection of system/consumer nodes).

iii. ***Enabling of data acquisition over any communication media***: The software will enable data acquisition over any of the locally and reliably available communication media: GSM/GPRS, EDGE, CDMA, PSTN, Low power radio etc.

iv. ***Provision to configure and manage technical parameters for communication media***: The software will be able to configure and manage technical parameters for the communication media used in the project.

v. ***Provision of remote reading & collection in both scheduled batch mode***: Remote reading collection will be possible in both scheduled batch mode (automated) as well as in the on-demand (real-time) mode.

vi. ***Features of scheduled mode of data collection***: In the scheduled mode of data collection, the software will allow reading cycles to be configured for either individual meters or groups of meters. Appropriate time windows for data collection from different meters based on location/type can be set. The data collection could be at any one of the pre-defined monthly, daily, hourly or quarter-hourly frequencies or at any user defined frequency greater than 15 minutes.

vii. ***Support for both inbound and outbound communication***: The software will support both inbound and outbound communication, i.e. data transfer could be initiated by either the remote meter or the central software.

viii. ***Type of Inbound communication***: At minimum, inbound communication will include event notification calls for power outage and restoration events. The event driven polling of meters shall enable pinpointing of faults during outages, defective or stopped meter.

ix. ***Type of outbound communication***: In outbound communication, the number of retries made by the software for failed meter readings will be configurable. If the meter cannot be read even after the specified number of retries, the system will raise an alarm and generate meter reading exceptions to enable tagging of cases for site verification.

x. ***Ability to retrieve both instantaneous and logged data***: The software will have the ability to retrieve both instantaneous and logged data from the meter.

xi. ***Support for import of meter data***: The software will support import of meter data from external sources in industry standard formats like ASCII, CSV or XML. It will also allow manual entry of meter data in exceptional cases only with appropriate user identification, security and audit trail. The input sources of meter data could be CMRIs (Common Meter Reading Instruments), substation log books etc.

xii. ***Synchronization of all meters to a common fixed reference***: The software will be able to synchronize the date and time of all meters to a common fixed reference. All the raw meter data entering the system via AMR or any external means is time stamped and stored for audit and further analysis.

2.3.6. **Network Topology Management:**

i. ***Ability to capture and maintain the geographic / administrative / regional hierarchy***: The software will be able to capture and maintain the geographic / administrative / regional hierarchy of a utility‟s control area, i.e., the tree hierarchy of zones, circles, divisions, subdivisions and substations constituting a utility.

ii. ***Ability to capture and maintain the electrical network topology***: The software will be able to capture and maintain the electrical network topology, i.e. substations, feeders, transformers and HT consumers.

iii. ***Flexible and Indian context oriented regional hierarchy and topology***: Both the regional hierarchy and topology would be specific to the Indian context and flexible enough to account for different voltage levels in Indian sub transmission and distribution networks e.g. 66/33/22/11/ 0.4 KV.

iv. ***Provision to capture and maintain associations between various metering nodes***: The software will be able to capture and maintain associations between various metering nodes (both system and consumer meters) and the regional hierarchy / network topology.

v. ***Typical list of System metering nodes***: System metering nodes could include AMR-enabled meters located at these network points, among others:
   a) Outgoing feeders from grid substations (at 33kV/ 11kV etc),
   b) Incomers (33kV etc) at the power/secondary substations,
   c) Outgoing feeders (11kV/ 6.6kV etc) from the power/secondary substations,
   d) inter-region power import / export tie points on sub-transmission/ distribution feeders,
   e) Distribution transformers (DTR) primary/secondary.

vi. ***Typical list of Consumer metering nodes***: Consumer metering nodes could include AMR-enabled meters located at the service points of selected H.T./L.T. consumers (e.g. those with load above 25kVA).

vii. ***Provision for modification in existing metering nodes***: The software will allow modification of existing metering node parameters.

viii. ***Provision to add virtual metering nodes***: The software will allow addition of virtual metering nodes and associate the same to the regional hierarchy / network topology.

ix. ***Provision to Navigate to any level of the regional hierarchy/network topology***: Navigation to any level of the regional hierarchy / network topology would be simple and intuitive via drill-down mechanism.

x. ***Provision to display SLD***: Software will be able to display SLD schematics for important network areas.

xi. ***Provision to depict Single line diagram***: Software shall have facility for creating data base and display of single line diagram of entire electrical network and embedding of acquired data (both analog & digital) of each feeder in real time.

xii. ***Supporting of automated rule based validation***: Software will support automated rule-based validation and estimation of raw metered data.

xiii. ***Supporting of multiple data states***: The software should support multiple data states for metered data through its transition from acquisition to analysis e.g. invalid, estimated, edited, verified, validated etc.

xiv. ***Configuration of validation rules***: The software will allow configurable validation rules that may be selectively applied to an individual metering node or groups of metering nodes or to channels common to different metering nodes.

xv. ***Logging of validation failures***: Validation failures would be logged for audit purposes.

xvi. ***Backing up of raw data***: Raw data would be backed up for audit purposes.

xvii. ***Provision of meter data estimation routine***: The software will have a meter data estimation routine that will be triggered on occurrence of validation failures.

xviii. ***Enabling of estimation routine***: The estimation routine can be selectively enabled/disabled.

xix. ***Provision of manual editing***: The software allows manual editing of metering data with audit trail.

xx. ***Provision for audit trail***: All data state transitions would be logged for audit trail.

2.3.7. Data Analysis & Charting:

i. ***Processing of validated meter data***: The software will enable processing of validated meter reading data for generation and storage of different time series channels. A channel would hold data pertaining to one particular parameter.

ii. ***Support for multiple channels for multi parameters***: The software will support multiple channels for multi parameter such as Voltage, Current, Frequency, Energy, Energy demand, performance indicator and event related data.

iii. ***Support for channels of different time series***: The software will support channels of different time granularities, i.e. hourly, daily, monthly etc.

iv. ***Support for different channels for different type of data***: The channels could hold direct measured data, derived (calculated) data, or data imported from external sources.

v. ***Viewing of time series data in tabular / graphical form***: User will be able to view time series data in tabular as well as graphical format.

vi. ***Ability to show status of time series data element***: The software will be able to highlight the state of a particular time series data element, e.g. if it is absent, edited, estimated etc.

vii. ***Comparison of multiple time series data***: The software will enable user to compare multiple time series together. The data series could pertain to the same channel or different channels.

viii. ***Facility for automated filling up of certain derived time series channels based on data in one or more other channels***: Automated filling up of certain derived time series channels based on data in one or more other channels will be enabled; e.g. data for the power factor channel of a particular metering node can be calculated using the data in the active power and reactive power channels of the same node. The latter two may have been directly filled with measured data from the meter.

ix. ***Provision of setting/editing of the conversion formulae***: The software will allow setting / editing of the conversion formulae for the derived channels. The conversion formulae can be based on simple arithmetic / trigonometric / aggregation functions.

x. ***Provision of aggregation of time series data***: The software should allow aggregation of time series data based on parameters like geography (regional hierarchy), network topology, time and customer category.

2.3.8. **Executive Dashboard:**

i. ***Provision of Executive dashboard***: Various utility offices, such as Circle, Division, Sub division etc. can interact with master Metering (AMR as well as non AMR enabled) / Billing database at data center to provide the below mentioned features.

ii. ***Provision of selective monitoring of summarized data***: The software would support selective monitoring of important summarized data at user-defined intervals that would aid in decision-making for distribution operations and planning actions.

iii. ***Highlighting of key performance indicators***: Key performance indicators, like AT&C losses, SAIFI, SAIDI, CAIDI (but not limited to) will be highlighted for every level of the network hierarchy.

iv. ***Energy balance at different network levels***: Energy balance at different network levels will be captured and displayed. This enables monitoring losses by region (subdivision/division /circle etc) and by network asset (transformer/feeder).

v. ***Monitoring of losses at different voltage levels***: Monitoring of losses at different voltage levels will be enabled.

vi. ***Display of load survey analysis***: The software will enable capture and display of data from multi-parameter load survey analysis. Monitoring of usage/demand patterns would thus be enabled.

vii. ***Monitoring of peak load***: Peak load at different network levels could be monitored.

viii. ***Monitoring of performance factors***: Performance factors like load factor, power factor, utilization factor, load duration curves would be monitored.

ix. ***Provision of transformer load management***: The dashboard will enable transformer load management. User will be able to monitor overloading/under loading, phase imbalance, load factor, utilization factor, load duration curves of transformers.

x. ***Provision of Feeder load management***: The dashboard will enable feeder load management. User will be able to monitor overloading / under loading, phase imbalance, load factor, utilization factor, load duration curves of feeders etc.

xi. ***Personalization as per the user's preferences***: The software would support personalization of the dashboard displays as per the user‟s preferences.

xii. ***Navigation from one level of network hierarchy to another***: Navigation from one level of network hierarchy to another will be intuitive and drilldown will be possible.

2.3.9. **Reports:**

i. ***Generation of reports based on the results of data analysis***: The software will be able to generate and display reports based on the results of data analysis. The reports module will be used as a more data heavy alternative to the Executive Dashboard.

ii. ***Reporting on energy flow, performance factor etc.***: The software will be able to display reports on all energy, demand, performance factor and event related data available for different metering nodes.

iii. ***Generation of reports with date range***: Each report will allow user to specify parameters like date range, end points for which reports need to be generated.

iv. ***Type of reporting***: The reports shall be Web based.

v. ***Exporting of reports to other applications***: The software will enable the user to export reports into other application software like ERP, Microsoft Excel etc. for further processing.

vi. ***Reports at Sub stations*** **:**

a) ***Finalization of reporting requirement as per utility***: Few typical reporting requirements are mentioned below, exact formats & requirement may be finalized as per the requirement of the Utility.

b) ***Facility to configure & view parameters in tabular/graphic form***: Software at substation level shall provide facility to view electrical network, configure & view parameters captured in tabular & graphical format.

c) ***Facility to query data based on date & parameter name***: Software shall have facility to query data based on dates & parameter name. Software shall be able to show trend for single parameter & comparative trend for multiple parameters based on the selection.

vii. ***Reports at Sub division office*****:**

a) ***Provision for comprehensive reporting and MIS facility***: Software at Sub division office shall provide comprehensive reporting facility. If required it may interact with data center and should provide fixed format as well as query based reports in tabular & graphic format as required by user.

b) ***Option to view data selectively in numerical / Graphical form***: The user should have option for viewing selective data like Instantaneous parameters, Cumulative Energy Readings, Tamper information's, Tariff wise Billing Data for each reset backup, Load Survey data, Meter Programming records. Option should be provided to view the Load Survey data in both numerical as well as In Graphical format with selective or composite view of parameters and in different styles viz. bar and line.

c) ***Generation of summary report of meter data for any load violation and tamper counts***: The software should scan through each meter data and generate a summary report of billing data, contract demand violation /

peak load violation/ off days violation along with tamper counts for that particular meter.

d) ***Provision of menu option for viewing each data report***: Menu option shall be given for viewing each data reports. The options will be enabled based on the availability of the data for the meter selected for data viewing. Each report header should give the information regarding the Meter serial Number, RTC, Date and Time of data collection, Type of collection, CT/PT details and other important consumer details.

e) ***Typical list of reports to be generated***: Reports should provide detailed information on Billing data, Load Survey data, Profiles, Tamper information, Programming mode records and other system irregularities. Following is a representative list of reports for different levels of the network hierarchy and for different timeframes:

- Energy balance report
- Consumption trends report
- Load factor report
- Reliability analysis Report
- Asset utilization report
- Electrical network monitoring report

f) ***Availability of extensive search options***: User should have extensive Search option for search using Meter number, Consumer Number, Consumer Name, Location, and Date of Reading of meter. An explore option should also be given for listing out all the meter data available in the system. This menu option will provide the list of data files sorted in the order of serial numbers, consumer account number and location.

g) ***List of a few typical reporting requirements***: Few typical reporting, requirements are mentioned below, exact formats & requirement may be finalized as per the requirement of the Utility.

- Display of Electrical Parameters (Load current in Amp, power factor, frequency, voltage, active, reactive and apparent power etc.) in Tabular Formats and as Trends (Graphs) Over Periods (e.g. for a week or month)
- Comparative tabular & graphical reports for more than one meter & more than one parameters (comparison of pure values as well as Min, Max, Sum, Average)
- Min, Max, Sum, Average electrical parameters values, its time of occurrence and duration of maximum and minimum values.
- Graphical Display of Maximum Power Demand Analysis
- Software shall have facility to query data based on dates & parameter name
- Software shall be able to show trend for single parameter & comparative trend for multiple parameters based on the selection.
- Support for sending report using Email or Alerts
- User Configurable Reports using MS Excel

- Detailed Error Reporting and diagnosis through Log Files and online display of Error Status
- Printing and Exporting of Reports to MS office.
- % availability factor of feeder (i.e. % of time for which power was available for feeders to know the reliability

viii. ***Reports at various Utility offices, such as Division, Circle, Head Quarter etc.:***

a) Reporting facility at various utility offices: Various utility offices can interact with Metering/ Billing database at Data center to provide extensive analysis & reporting facility. It shall also have extensive search options and should provide fixed format as well as query based reports in tabular & graphic format as per the requirement of the utility and described in detail above (i.e. Reports at Sub division offices).

b) Geographic/ administrative/ regional hierarchy wise reporting facility: The various offices of the utility e.g. zones, circles, divisions etc. can login to the system for generating and viewing various MIS reports, statistical data, performance indices etc. as per their requirement.

2.3.10. Events and Alarm Notification:

i. ***Monitoring of important events***: The event list shall contain events, which are important for monitoring. The date and time has to be displayed for each event.

ii. ***Chronological registration of events***: The events shall be registered in a chronological event list, in which the type of event and its time of occurrence are indicated. It shall be possible to store all events in the computer. The information shall be obtainable also from printed Event log.

iii. ***Listing of faults, errors and limit value violation in alarm list***: Faults, errors and limit value violation of all values occurring shall be listed in an alarm list. Audible annunciation must be provided on receiving alarm. It shall contain unacknowledged alarms and persisting faults. Date and time of occurrence shall be indicated.

iv. ***Summary display of alarm situation***: The alarm list shall consist of a summary display of the present alarm situation. Each alarm shall be reported on line that contains :

a) Alarm date and time
b) Name of the alarming object
c) A descriptive text
d) Acknowledgement state

v. ***Acknowledgement of alarms***: The operator shall be able to acknowledge alarms. Acknowledged alarms shall be marked at the list.

vi. ***Typical list of items on which system can generate alarms***: The system will analyze time series / meter data and generate alarms/notifications. Following is the representative list of items on which system may generate alarms :

a) Alarms based on consumption patterns
b) Alarms based on loading conditions
c) Alarms based on tamper detection
d) Alarms based on outage detection
e) Alarm based on violation of limit values
f) Ability to configure criticality / priority of the events

vii. ***Framework to configure thresholds for generating alarms at each end-point***: The system will have framework that allows user to configure thresholds for generating alarms at each end-point. (e.g. one set of end points, user should be notified if daily consumption exceeds Y kWh and for some other end points alarms should be generated only if the daily consumption exceeds X kWh).

viii. ***Alarm on failure in communication, loss of data etc***.: The system will also generate alarms based on any failure in communication, missing/loss of data.

ix. ***Supporting of alarm/ notification dispatch via communication Media***: The system will support dispatching alarms/notification using various communication media like SMS, E-Mail, Desktop Application etc.

x. ***Ability to deliver alarm/ notification to multiple recipients***: The system will allow each alarm / notification to be delivered to multiple recipients. (e.g. alarms corresponding to outage at DTR level should be sent to a J.E. and an S.E.)

xi. ***Provision for turning certain alarm generation on/off as per user preferences***: The system will allow turning on/off certain type of alarms generation (at system wide level or for particular end point) based on user preferences. (e.g. if one does not want any Communication Failure alarms, he/she can turn off the alarm generation for this criterion).

xii. ***Provision for turning certain alarm dispatch on/off as per user preferences***: The system will allow turning on/off dispatching alarm notifications to required recipients. e.g. if Chief Engineer, does not want to receive any alarms for some reasons, system should be able to turn-off the same)

xiii. ***Provision to acknowledge or ignore events/ alarms***: The system will allow user to acknowledge or ignore events/ alarms. System will also allow user to log the actions taken, if any, for any particular event.

xiv. ***Setting of different priority levels for different events/ alarms***: The system will support different priority levels for different types of events/ alarms.

xv. ***Provision of different dispatch schedules for different types of events/ alarms***: The system will support different dispatch schedules for different types of events/ alarms. (e.g. Outage Alarms to be dispatched within 5 minutes of receipt and Contact Demand violation alarms should be dispatched before every billing cycle start).