



ISGF Advanced Distribution

R-APDRP STUDY REPORT



ISGF ADVANCED DISTRIBUTION

Table of Contents

TABLE OF ABBREVIATIONS.....	3
BACKGROUND.....	4
EXECUTIVE SUMMARY	5
DELIVERABLES	7
R-APDRP Analysis.....	7
PART A IT	8
PART A SCADA.....	14
PART B	19
PART C	23
Revised Scope	25
Revised Implementation and Monitoring Model.....	29
Scope and Timeline Revision	29
Project Monitoring:.....	32
Monitoring Methodology - National (Programme) Level.....	32
Project Monitoring Methodology - Utility (Project) Level.....	33
R-APDRP – Implementation Process Model	35
Recommendations: Changes to specifications & Guidelines	38
R-APDRP Part A IT G1 Specifications	39
R-APDRP Part A IT G2 Specifications	40
R-APDRP Part A IT G3 Specifications	50
R-APDRP Part A SCADA MTS Specification.....	53
R-APDRP Part B	58
Recommendations for Process Mapping	60
Analysis of Capability and Readiness to Adopt.....	63
Budget for training and capacity building:	66
Proposed Capacity Building (for Smart Grids)	66
Proposed Programme & Estimated Costs.....	67
Standards, Architecture and Security.....	68
Acknowledgements.....	71
Annexure 1: Feedback from ISGF.....	72

TABLE OF ABBREVIATIONS

2G	2nd Generation wireless telephone technology	MCS (Part B)	Metering & Communications Strengthening
3G	3rd Generation wireless telephone technology	MDAS	Meter Data Acquisition System
AMI	Advanced Metering Infrastructure	MDASP	Meter Data Acquisition Service Provider
AMR	Automated Meter Reading	MDM	Meter Data Management
AT&C	Aggregated Technical & Commercial (losses)	MoP	Ministry of Power
BIS	Bureau of Indian Standards	MTS	Model Technical Specification
BoG	Board of Governors	NPC	National Planning Commission
BoQ	Bill of Quantities	NSP	Network Service Provider
CCC	Customer Care Centre	O&M	Operation & Maintenance
CEA	Central Electricity Authority	OAS (Part A)	Operational Applications Strengthening
CTQ	Critical to Quality	OEM	Original Equipment Manufacturer
DAC	Distribution Automation & Control	OMS	Outage Management System
DAS	Distribution Automation System	PFC	Power Finance Corporation
DisCom	Distribution Company	PMO	Project Management Office
DMS	Distribution Management System	R-APDRP	Restructured Accelerated Power Distribution Reform Programme
DNS (Part B)	Distribution Network Strengthening	R&D	Research & Development
DPR	Detailed Project Report	RfP	Request for Proposal
DT	Distribution Transformer	RfQ	Request for Quotation
EHS	Environment, Health and Safety	RMU	Ring Main Unit
ERP	Enterprise Resource Planning	RTU	Remote Terminal Unit
FC (Part B)	Fiber Connectivity	SCADA	Supervisory Control and Data Acquisition
FLISR	Fault Location, Isolation and System Restoration	SDC	SCADA Design Consultant
FPI	Fault Passage Indicator	SDLC	Software Development Life Cycle
GIS	Geographical Information Systems	SEB	State Electricity Board
GPRS	General Packet Radio Services	SG	Smart Grids
GSM	Global System for Mobile Communications	SIA	SCADA Implementation Agency
GSP	GIS Service Provider	SRS	System Requirement Specification
HR	Human Resource	TIPIEA	Third Party Independent Energy Auditor
HT	High Tension	WG1	WG1 Advanced Transmission Systems
IA	Implementation Agency	WG10	WG10 Cyber Security
IEC	International Electromechanical Committee	WG2	WG2 - Advanced Distribution Systems
IO (Part A)	Integrated Operations	WG3	WG3 Communications for Smart Grids
ISGF	India Smart Grids Forum	WG4	WG4 Metering
ISO	International Standards Organisation	WG5	WG5 Consumption and Load Control
IT	Information Technology	WG6	WG6 Policy and Regulations
ITC	Information Technology Consultant	WG7	WG7 Architecture and Design
ITIA	Information Technology Implementation Agency	WG8	WG8 Pilots and Business Models
LT	Low Tension	WG9	WG9 Renewables and Micro-grids

ISGF Advanced Distribution

R-APDRP STUDY REPORT

BACKGROUND

In an effort to incorporate views of diverse stake-holders, the Ministry of Power (MoP) directed the India Smart Grid Forum (ISGF), (a PPP initiative established by the Ministry of Power) to study the on-going R-APDRP in terms of Scope, Implementation Strategy and Specifications and make appropriate suggestions so that suitable improvisations could be made to the programme when it is extended to the 12th Five Year Plan. Consequently, the Board of Governors (BoG) of the ISGF constituted a Study Committee (SC) under the Chairmanship of Shri Ram Pillai of Tata Power, who is also the Chair of ISGF's Working Group No.2: Advanced Distribution.

The objective of the SC was to leverage the existing work carried out under R-APDRP by sharing best practices as well as understanding the challenges and recommend how the current methodology and technology could be improved.

While the key focus areas of R-APDRP to reduce AT&C losses will remain and continue to be the main drivers of the programme, it is expected that as a result of the study, other objectives are identified and aligned with the development of Smart Grids envisaged by the Ministry of Power.



In order to ensure full comprehension, the study covered a review of the scope, specifications and processes of R-APDRP parts A & B, in the form of interviews, gap analysis and benchmarking exercises.

It was essential that all stakeholders' experiences were captured within the scope of the study, and therefore the SC carried out interviews with DisComs, ITCs, ITIAs, SDCs, SIAs and Part B consultants and contractors to discuss the successes, challenges and suggestions for how further efficiencies could be gained whether related to product or processes.

The views presented in this report do not necessarily reflect those of the Govt. of India, discussants, Forum Members etc, they are collective and based on a consolidation of all feedback from stakeholders as well as experts.

EXECUTIVE SUMMARY

The project has involved interviewing 8 representative state utilities and all of the ITCs, ITIAs, SDCs and SIAs associated with them under R-APDRP as well as some Part B contractors, GISSPs, MDASPs and the regulators of 2 states. In addition to this exercise, the specifications (SRS and MTS) and processes have also been reviewed. The objective of the interviews was to highlight the best practices to be leveraged, the challenges to be addressed and the scope to be expanded, when considering the revised model for R-APDRP including those initiatives proposed by the India Smart grids Forum, to be implemented in the 12th plan period.

Whilst all Part A IT projects have faced some challenges, the levels have varied from some projects experiencing huge difficulties to some with negligible issues. It is widely recognised that the biggest challenges faced were with the implementation of GIS and AMR/MDM/MDAS and these were mainly due to the capacity of the utilities and implementing agencies and the time frames permitted for completion of the project. The capacity issues can be attributed to the mass deployment 'big-bang' strategy for the project, which seriously depleted the limited resources of the supply chain and is not expected to recur as the project is extended. Also, it is understood that as a result of a study carried out by CEA and NCP the time frames for implementing GIS are likely to be extended.

Where the Part A IT projects have been most successful, it has been due to the formation of a strong core team within the utility, wide scale communication and awareness programmes dedicated to all stakeholders involved in the project, a well structured project charter that clearly defines all roles and responsibilities, early identification and action taken to address skills shortfalls and a partnership type approach between the utilities and their implementing agencies. The report will recommend how these activities can be formalised and included in the future scope of R-APDRP and how a forum of DisComs could provide a platform for knowledge and best practice sharing as well as platform for addressing challenges.

A lot has been said about the rigidity of specifications and delays caused in the approval of DPRs as a result of non-adherence to specifications. As the initiative has now reached some level of maturity some flexibility should be given allowing DisComs to size equipment etc. according to their needs. This report provides further recommendations detailing how the specifications could be amended to ensure they are fit for purpose, current and even future proof and yet flexible.

Another concern is the payment terms to implementation agencies which are heavily orientated towards the end of the project and whilst this method was introduced to guarantee full implementation of the projects, the result is that even though the majority of work has been completed, there have been some delays which have meant that the towns cannot be signed off and therefore all ITIAs are experiencing negative cash flow and would be very cautious about participating in the future. It is widely recognised that the terms have already discouraged many enterprises from participating and any further discouragement would jeopardise the capacity of the supply chain to deliver even further. With this in mind, the report provides recommendations on a revised mutually beneficial implementation and monitoring and a payment strategy related to completed feeders rather than towns. However it should also

be noted that bid prices have drastically reduced over time and all agencies should be mindful not to be over competitive thus making the projects loss making from the start.

Regarding Part B, all stakeholders feel that there are issues with the design, planning and implementation of this part as it is day-to-day business for all involved. The report however will highlight that better coordination is required between part B and part A SCADA in order to ensure that equipment is 'SCADA ready' when it comes to implementation. Also that as R-APDRP is an initiative designed to reduce AT&C losses then the equipment used should at least be compliant with BIS standards and should be efficient e.g. low loss transformers.

In many cases Part C Capacity Building has been an after thought and all of those involved in projects that have faced difficulty have stated that more training for all stakeholders is required. As we have mentioned above the most successful projects identified the capacity gaps at the very beginning of the planning stage for R-APDRP and consequently submitted a DPR for a loan approval to provide funds for addressing these gaps from day 1. The report will therefore recommend that a capacity assessment be carried out as part of the initial DPR planning in order to ensure that all stakeholders are ready to participate.

The sustainability and success of R-APDRP will be directly proportional to the level of upkeep. For example, currently there is no scope for updating GIS data as changes are made and whilst the majority of utilities continue to struggle with resource restrictions there is no internal mechanism for keeping information accurate and up to date. In the short term it is recommended that R-APDRP provide a platform for this to take place, whether through strengthening the DisCom teams or adding a service to be outsourced in the project scope.

Finally, to ensure that R-APDRP in it's evolving forms continues to be successful; the report outlines a recommendation for project monitoring both at a national (programme) level and at the utility (project) level. The objectives being to highlight and share best practices as well as provide an early warning system for any issues leading to an early resolution for corrective action.

In general Utilities are not yet reaping the benefits of R-APDRP and in some cases they feel their workload has increased. However they do foresee that the situation will improve and eventually their businesses will gain from their efforts. Overall they believe that R-APDRP has provided a process for improvement in customer service and bringing transparency & accountability into utility operations, which would not have existed otherwise. They also feel as and when R-APDRP is fully operational, it will be a stepping-stone on the journey towards making their business more successful and sustainable.

DELIVERABLES

The report includes the following deliverables

1. A synopsis of R-APDRP processes and products as implemented thus far, spanning the lifecycle of technology/provider analysis, decision-making, and execution and its adaptability for transition towards smart grids.
2. A proposed revised scope for R-APDRP program for the 12th Plan, taking into consideration the progress made currently under R-APDRP and how it can be leveraged to meet the SG vision.
3. A pragmatic implementation model that ensures efficient utilization of the resources to be invested, including a comprehensive monitoring and control mechanism.
4. Suggestions on amendments to specifications for Part A and guidelines for Part B & C, required for smoother implementation of the systems envisaged for R-APDRP and any additional systems proposed in the new edition of the programme as per the ISGF roadmap for Advanced Distribution.
5. An analysis of the readiness and capability of all stakeholders, including human resources, that is needed to implement the program as detailed above
6. A proposed programme and the estimated cost for this modification.
7. Proposed high-level recommendations on standards, architecture and security features that will ensure scalability, which can be submitted to expert groups as suggestions of, further work.

R-APDRP Analysis

Over the period of 2 weeks an extensive survey was carried out involving key stakeholders from DisCom/SEBs, ITCs, ITIAs (GSP, MDASP, SI etc.), SDCs, SIA, to discover best practices, understand challenges and gather recommendations on improvements, as well as understand DisCom/SEB's expectations, needs and roadmaps for smart grid solutions such as load management, integrating renewable energy etc.

The survey included a review of both products and processes and all results stored in a database, the data from which was then analysed to form the following conclusions:

PART A IT

Part A IT Scope

BEST PRACTICES

GREATEST CHALLENGES

<p>1</p> <p>The availability of model documents for bidding and technical specifications has resulted in consistency and timesaving for DisComs who would have otherwise incurred time in preparation of RfQ, RfPs and other documents for bid process management.</p>	<p>It has been observed that some of the DisComs were unaware that while they can customize sections G1 & G2 of the SRS, the same flexibility is not available for changes to G3. Therefore DisComs who demanded changes to section G3 have faced time delays for approval of their DPRs.</p>
<p>2</p> <p>The initiation of and adherence to a Project Charter by some DisComs has provided clarity on responsibility and improved decision making processes.</p>	<p>There is currently no mechanism to keep information up to date. E.g. GIS survey data quickly becomes obsolete as new connections and electrical assets etc. are added.</p>
<p>3</p> <p>Some DisComs have developed a strong communication plan at project conception and maintained it throughout the project lifecycle, which has resulted in continuous buy-in and motivation by all stakeholders.</p>	<p>The restriction to certain sized towns means that data from non-R-APDRP areas has to be integrated with R-APDRP information. This leads to huge inaccuracies in energy audits, as data is not consistent.</p>

RECOMMENDATIONS FOR IMPROVEMENTS

<p>1</p> <p>The process for seeking changes to any part of the SRS should be re-communicated to the DisComs. However, It is felt that since the initiative has now reached some level of maturity greater flexibility should be given allowing DisComs to seek changes to the SRS e.g. sizing equipment etc. according to their needs. Additionally DisComs should actively participate in any revision to the SRS templates.</p>	
<p>2</p> <p>It is critical for the programme's success to have a mechanism to ensure that all information is captured and kept up to date. The following options could apply: In-house DisCom team employed to update GIS information on a regular basis. An outsourced management contract where the service provider would update all information associated to new connections etc.</p>	

- 3 As so much time is wasted making attempts to fit modems to out of date meters there needs to be a better system for coordination. Perhaps only new meters should be included in the scope until the DisCom can guarantee that the meters are fit for the purpose of the project.

- 4 States with more than 1 DisCom should be treated as separate projects. In the majority of cases individual DisComs are having their own systems and this would also make it easier for separation, should DisComs be privatised/franchised in the future.

Part A IT Planning & Preparation:

BEST PRACTICES	GREATEST CHALLENGES
<p>1 Constant coordination and cooperation between the nodal project team and PFC results in faster resolution of issues etc. E.g. easier approval of the DPR.</p>	<p>Often due to changes in senior management motivation and momentum are reduced and extra unnecessary time has to be dedicated to re-explaining the project scope, structure cost-benefits-costs etc.</p>
<p>2</p>	<p>Coordination between multi-DisCom states is challenging as stakeholders have different objectives and often have diverse systems that need to be immigrated/integrated.</p>
<p>3</p>	<p>Since the project scope (especially the IT Part) was completely new to many DisComs, it was felt that they did not have enough time to acquaint themselves with the new scope and processes which resulted in unnecessary mistakes to be made during preparation of DPRs and the bid process for selection of ITIA.</p>
<p>4</p>	<p>Input data provided by the field staff for preparation of DPR is often inaccurate.</p>

RECOMMENDATIONS FOR IMPROVEMENTS

- 1 Use of a project portal that can show a snapshot of project progress and the next steps. Editing rights can be limited to a few users but all project members can access project information as and when required. In cases where there is more than 1 DisCom involved, specific access to the Project Portal should be provided to all the parties.
- 2 DisComs need to understand that to ensure success of the programme and reap the expected benefits, they should be more involved in the project planning process.
- 3 Time provided for preparation of DPRs could be increased and this would ensure less mistakes and discrepancies. However as all stakeholders are now more familiar with the procedure this may not be necessary.
- 4 There should be an option for pilot projects, as DisComs do not feel confident to manage full deployment in the 1st instance. This would help in documenting challenges and best practices for implementation, which can be utilised later when the project is fully deployed.

Part A IT Implementation:

BEST PRACTICES

- 1 Adopting a partnership approach to solving problems provides quicker solutions. It has been observed that some DisComs are more proactive and have held workshops with all stakeholders to resolve issues.

GREATEST CHALLENGES

- 1 Serious concerns have been raised over the capability of the ITIA teams. Often the actual project team comprises of junior resources with no relevant background/experience. The CVs of people submitted for evaluation seldom reflect those members of the implementation team.
- 2 The time allocated for implementation of certain modules such as: GIS, AMR, MDM, MDAS is insufficient. (Currently under review by NPC/CEA).

Part A IT Implementation (Continued):

3

Skewed payment terms for implementation have resulted in negative cash flow for IAs which has made them and others vary of further participation in the programme.

4

Items under complete control of the utility are often found to not be ready (e.g. construction of buildings). In the absence of which the implementation agency cannot move ahead and this further delays their payments.

RECOMMENDATIONS FOR IMPROVEMENTS

1

Revised Implementation schedule that provides for pro-rata time in relation to the number of towns under scope of work to be considered. For example 1 yr. required for 1st town (New projects) and a certain allocated time for each town after that.
An alternate study being conducted by CEA has reviewed the time periods and should provide recommendations for changes if any.

2

Payment terms to be revised and based on completion of feeders and not towns. Often some of the delays in towns are out of the control of the ITIAs so they should not be penalised for this.

3

Key ITIA project team members should not be changed (without prior approval from the utility).

4

Before selection of ITIA, the existing IT/OT solutions should be studied (As-Is survey) carefully to understand what can/cannot be integrated with R-APDRP.

5

Consultants working for the utilities (ITC & SDC) should also be involved during the PFC review meetings and for the duration of the implementation and should act as a mediator between the DisComs and IAs especially in matters associated with compliance of specifications etc. Their role should change from 'assisting' to supporting.

6

The implementation roadmap should be such that the utility should start work on preliminary activities such as civil construction of Customer Care Centre (CCC) ahead of the time before which the IT Implementation Agency would need to take control of the CCC.

Part A IT Implementation Recommendations for Improvement (Continued):

- 6 There should be strict coordination between AMR implementation and metering upgrades in the field. It is not the ITIA's responsibility to audit the existing metering. The DisComs should provide information on the meters that are fit to have modems fitted to them first and only after meter upgrade for the remaining, should the IA be sent to fit the modems.

- 7 Problems with connectivity could be solved by having a push function on the data from the meter so that data could be sent during less congested times. Whilst this exists in the specification, the process is longwinded, as the DisComs/ITs have to apply to the meter manufacturers for protocol information. Time could be saved if there was some scope for this activity or if it was part of an as-is study carried out by the consultant during the planning/preparation phases.

- 8 Where Data Centres are not ready for example due to delays in construction then either a facility should be hired or managed through hosted services.

- 9 Only proven software, which has been successfully implemented on a similar scale and project type should be considered for implementation.

Part A IT Ability & Capacity (Readiness):

	BEST PRACTICES	GREATEST CHALLENGES
1	Formation of a dedicated project team within the DisCom and wide-scale communication and awareness programmes/charters dedicated to all stakeholders involved in the project, was initiated by certain DisComs.	Insufficient staff allocation by the utility.
2	There is a certain consensus and confidence that the project will lead to benefits in terms of ability to reduce commercial losses.	Lack of sufficient training for utility staff on project requirements, specifications and benefits from the project leads to unnecessary resistance and delays.

Part A IT Ability & Capacity (Continued):

- | | | |
|---|--|---|
| 3 | For some DisComs interviewed, having a core team with competencies in all aspects of R-APDRP such as IT, GIS, MDAS etc. has resulted in a better-dedicated approach and smoother implementation. | Lack of involvement and ownership by all stakeholders in the project. It is important that ownership for the task is at the operational level not at the central level. |
|---|--|---|

- | | | |
|---|--|---|
| 4 | Training needs assessment carried out during the planning phase to identify gaps and prepare DPR/apply for loan to address gaps. | R-APDRP has led to an increase in workload with no immediate benefits in sight. |
|---|--|---|

RECOMMENDATIONS FOR IMPROVEMENTS

- | | |
|---|---|
| 1 | Recommendations on a well structured project charter that clearly defines all roles and responsibilities, early identification and action taken to address skills shortfalls and a partnership type approach between the utilities and their implementing agencies. |
| 2 | Awareness training about the project scope, benefits and processes to be followed etc. should be given at the start of such a big project and repeated during the project. |
| 3 | Utility staff should also be trained for preparation of DPR and all other basic requirements, IT, GIS etc. |
| 4 | Formats for reports to be made from data collected from Business Intelligence should be provided along with some basic training on how to draw inferences from such data. |

Note: Further recommendations on capacity building are covered in the revised scope and analysis of capability and readiness to adopt sections of this report.

PART A SCADA

Part A SCADA Scope:

BEST PRACTICES

GREATEST CHALLENGES

1

Working on the project and interactions with stakeholders involved helped in building understanding of new technologies.

Current scope provides only partial control to the SIA for all the work to be completed. E.g. delay in construction of control centres etc. leads to overall project delays.

RECOMMENDATIONS FOR IMPROVEMENTS

1

SCADA roll out should be based on 2011 census data not 2001 which would incorporate more cities. (This is expected to be done covered in new edition)

2

SCADA control room housing should be included as part of the SCADA scope as currently the SIA has no obligation other than to locate servers in a room. However inclusion of civil part within the IA's contract may not be the best solution. Instead the implementation schedule should require for civil construction to start before the bid is placed for SIA.

3

SCADA has to be integrated with GIS so there should be some responsibility on both parties to ensure smooth integration.

4

The user interface for SCADA/DMS system shall be web enabled.

5

GIS is considered to be the Asset Master. The implementation of the network model in DMS is dependent on the availability of the asset master. If the GIS implementation gets delayed, the DMS SI should not be expected to manage the asset master in the interim period. It should be the responsibility of the GIS vendor. This understanding is missing with almost all utilities and needs to be clarified.

6

Some substations are 35 years old and therefore not SCADA ready. There needs to be a provision for upgrade/coordination with part B so substations to be included as part of SCADA are upgraded accordingly.

Part A SCADA Planning & Preparation:

BEST PRACTICES

GREATEST CHALLENGES

- | | | |
|---|--|--|
| 1 | The availability of model documents for bidding and technical specifications has resulted in consistency and timesaving. | Availability of information in the field, Capacity of stakeholders to understand the concept of SCADA. |
| 2 | | Time period for surveys was not adequate and should be proportional to number of towns. |

RECOMMENDATIONS FOR IMPROVEMENTS

- 1 Review of MTS (Model Technical Specification) to ensure it is up to date which is being discussed later in this report. Flexibility to DisComs to adjust some part of specification to suit their needs. Any changes to the MTS should be done by way of an addendum while the main document should be left unchanged. This will save time in figuring out where all the changes have been made.
- 2 There needs to be a mechanism for up-scaling maybe in the form of an addendum e.g. for more substations as identified during the survey but not in the original DPR.
- 3 It is in the best of interests of the utility and bidders that if there is any extension to be given for bid submission, the same should be communicated at least 2 days before the original bid submission date. Further extension of bid submission should not be a normal practice where the number of bids received by the utility is not sufficient. This reduces transparency in the bid process.
- 4 Utilities / Consultants should be asked to incorporate all changes from MTS in a separate Annexure giving links to specific clause in MTS. This drastically improves efficiency of bid preparation.
- 5 Model RfP for selection of SIA provides bidders to quote for ""Network Connectivity Charges for Link for 1 year post commissioning"" - under Form 2 SCADA/ DMS Control Centre Cost BOQ. This quote should be for 3 years instead of 1 year.
The reason is that the investment that a NSP has to make to provide these lease lines is huge. So putting it for 3 years will allow them to get sufficient recovery from the CAPEX and give the cost benefit to the utility as well.

Part A SCADA Planning & Preparation (Continued):**RECOMMENDATIONS FOR IMPROVEMENTS (Continued)**

- 6 There should be clarity on whether a utility can go ahead with the tender if a single bid is received. This is missing at present. Price bids should not be opened unless there is a clear directive.
- 7 IT package demands IP55 class panel for GPRS modems for FPI locations (which are supplied through separate package). Both being electronic items, it would be more prudent to have them in the same IP55 class enclosure. Communication protocol between FPI and GPRS modem should be defined in the MTS.
- 8 Utilities should refrain from changing clauses in BG formats. Such changes if any should reflect ground reality.
- 9 Present guidelines do not provide for any assessment of the number of projects/towns a SI is capable of executing simultaneously. This should be incorporated.
- 10 Makes of major equipment should be specified in SCADA contracts or at least minimum standard should be stated.

Part A SCADA Implementation:

BEST PRACTICES	GREATEST CHALLENGES
1	Availability of information, Capacity of stakeholders. SIA is struggling to get relevant information from the GIS module.
2	The time frame for implementation is currently irrespective of the number of towns and town sizing. The same time is allocated whether there are 4 towns / towns having fewer than 25 substations/100 feeders or 80 towns/large cities having more than 100 substations/800 feeders.
3	Absence of a core project team at the utility leads to lack of coordination between the utility and the implementation agency, which leads to time delays.
4	Delays in deliver of equipment in part B related to SCADA implementation leads to overall project delays.

RECOMMENDATIONS FOR IMPROVEMENTS

1	SCADA should be coordinated with Part B to ensure equipment is SCADA ready.
2	SCADA implementation periods should not be fixed but should be according to the number of towns and town sizing. 1 year for 1st town and then a fixed term for each town after that. (Currently being considered by NPC/CEA).
3	The implementation roadmap should be such that the utility should start work on preliminary activities (such as civil construction of Data Centre) ahead of selection & appointment of the SCADA Implementation Agency.
4	There is currently no formalised responsibility for implementing GIS data within the SCADA. One solution as recommended by this report (See section 2 and 3) is to have one part of the project completely dedicated to integration of operational and IT systems.

Part A SCADA Implementation (Continued).

5 As per GCC 13.1-7 G the bandwidth charges are based on actual claim by the SIA and post verification by the utility. There should be some maximum timeframe within which the utility has the responsibility to verify such claim and make payments. This should not be left open ended.

6 As per GCC 13.1-7 H the complete 100% FMS charges are paid to the SIA at the end of each year. This should be changed to 10% advance and 90% at the end of each year, since the SIA requires some amount of advance money for mobilisation of resources.

7 As per GCC 13.1-4 Eligible payments against invoice submitted shall be released within 45 days of submission of invoices. Too long payment delivery time affects the cash flow of contractor, which in turn loads such costs in his bid. Therefore it is recommended that the utility should drive to lessen its payment delivery time – from say 45 days to 30 days. Further in case where payment is delayed by the utility beyond the prescribed time, the contractor should be paid an interest on such delayed amount at the rate of say SBI PLR.

Part A SCADA Ability & Capacity (Readiness):

BEST PRACTICES

GREATEST CHALLENGES

1 Training needs assessment carried out during the planning phase to identify gaps and prepare DPR/apply for loan to address gaps.

Resistance from the utility field staff due to their perception that automation will eventually lead to loss of jobs.

2

Lack of understanding of SCADA, DAS etc. in Utility teams. Requires effort by IAs to train staff.

RECOMMENDATIONS FOR IMPROVEMENTS

1 There needs to be a positive communication and awareness training to make field workers understand that by implementing automation, they will not lose their jobs but that it will improve efficiency, safety etc.

2 Carry out training needs assessments during the planning phase to identify gaps and prepare DPR/apply for loan to address gaps.

PART B

Part B Scope:

BEST PRACTICES

GREATEST CHALLENGES

1

In the absence of any guidelines on the minimum size of projects from PFC, the DisComs apparently scope projects which are smaller in size. Further the qualification requirements set are not stringent (due to the capability of the companies who would bid for such small sized projects) and can therefore result in lower standard products being supplied or jeopardise the completion of the work in a timely manner.

2

It is observed that often the BoQ does not lists certain items, which are later, required for completion of projects. In such cases time is lost in finalising prices for such additional items, since the price bid does not reflect the same.

RECOMMENDATIONS FOR IMPROVEMENTS

1

As R-APDRP is a AT&C loss reduction initiative, at the least energy efficient/low loss equipment should be specified (see section on specification).

2

As a minimum BIS standards or IEC where BIS is not available should be adhered to. (See section on specification).

3

Standard bid documents for projects to be carried out under Part B should be prepared. These standard documents should specify the minimum qualification requirements, clear clauses for how to deal in case of scope variations etc.

Part B Planning & Preparation:

BEST PRACTICES	GREATEST CHALLENGES
1	Understanding by DisComs on the risk of loan conversion. They say they are unsure whether they can prove the losses have been reduced according to this part of the project. PFC say that all loans will be converted providing losses are below 15%.
2	Time period for project planning was not adequate.

RECOMMENDATIONS FOR IMPROVEMENTS

1	Re-communication of process for payment and loan conversion on Part B.
2	Pre-bid meeting should be a mandatory procedure and there should be some enforcement on the utility that the issues raised by the contractors before and during the pre-bid meeting are answered to satisfaction. (Project management rules to apply).

Part B Implementation:

BEST PRACTICES	GREATEST CHALLENGES
1	It is observed that DisComs have started on projects under Part B only after a major portion of work under Part A has been completed. This has resulted in delays in SCADA implementation.
2	Absence of a project team/project charter leads to lack of coordination between the utility and the implementation agency, which leads to time delays.

Part B Implementation (Continued):

3

Details provided under DPR (prepared by the utility and used as a base document for bidding) do not match with ground realities, leading to frequent changes in the works order. This causes time delays. This also results in final contract value being different to the original contract, which has been signed. Therefore the original furnished Performance Bank Guarantee is often rendered short.

4

Utility staff take considerable time taking over the project from the contractor. Since the contractor's payment is linked to 'handling over the project to the utility' their payments are delayed.

5

Utilities change the BoQ quantities of some items, which leads to discrepancies, and the contractor is not paid for over-supply and then has to store the item at his own warehouse.

RECOMMENDATIONS FOR IMPROVEMENTS

1

There needs to be better coordination between Part A and Part B to ensure that field equipment is ready for SCADA implementation.

2

Scope of work should be frozen at the time of work order issuance.

3

If procured quantity by the vendor is in excess of requirement, and such extra procurement has been because of direction/ order by the utility – then the utility should pay for such over capacity and store the item at utility's warehouses/ stores.

Part B Ability & Capacity (Readiness):**BEST PRACTICES****GREATEST CHALLENGES****1**

Projects covered under Part B are similar to projects done by the utility in past – therefore sufficient in-house capability to handle such projects already exists.

RECOMMENDATIONS FOR IMPROVEMENTS**1**

Provide training on new technologies, standards etc. to ensure stakeholders are up to date.

PART C

Part C Scope:

BEST PRACTICES

GREATEST CHALLENGES

- | | | |
|---|--|---|
| 1 | Coordinated training and capacity building needs assessments carried out at the project conception to identify gaps and action taken to address gaps through preparation of DPR/Application of loan. | General absence of skilled manpower for all R-APDRP activities. |
| 2 | . | Lack of understanding of availability of funds for part C, processes/qualification criteria, availability of structured training etc. |

RECOMMENDATIONS FOR IMPROVEMENTS

- 1 Re-communication of Part C processes to all stakeholders.
- 2 All utilities should be compelled to carry out training and capacity needs assessment during project conception and implement action plan accordingly.
- 3 A study at a central level to see which courses are consistently needed by all and action taken to design/roll out these courses.
- 4 IT Skill training for all stakeholders.
- 5 Utility business induction for all implementation agencies before starting work on projects.
- 6 Awareness training to deploy positive communication detailing the benefits to individuals.
- 7 Strong project charter with clear roles and responsibilities and promotion of partnership culture between utilities and implementation agencies.

Part C Ability & Capacity (Readiness):**BEST PRACTICES****GREATEST CHALLENGES**

1

IT illiteracy and uncertainty cause barriers to acceptance of new technology & processes.

RECOMMENDATIONS FOR IMPROVEMENTS

1

Train the Trainer Training and one to one training to all the officers and individuals who will be working on the system.

2

Change management driven by utility senior management team will enhance confidence of the working staff and shall help in mitigating their fears.

3

Large Project/ Programme Management is a valuable and critical skill. Training programmes could provide more focus on tools and methodologies to handle complex and large projects.

Revised Scope

As well as considering the inputs from the previous exercise, this part of the project involved integrating the requirements of the ISGF vision for Advanced Distribution in the 12th plan.

To ensure full coordination between all state level projects it is recommended that all DisComs carry out a full system study and develop a short, medium and long term plan for network expansion, based on forecasts for growth and taking into consideration national and state wide targets for access to electricity, developments in the electricity act, environmental impact mitigation etc. This plan would provide a strategic view to the business priorities for the DisCom and direction on the implementation of R-APDRP.

To ensure sustainability there has to be a process for updating/maintaining all systems.

Further to this the SC recommends the following modifications be made to the scope of R-APDRP for inclusion within the 12th plan:

Part A Planning (NEW)

- 1 Structure of Core Team at a central level and field (town) level for ownership and implementation of the project. (See section 3 below) To be started from day 1 of conception of the project. Justification: More coordination throughout the project and ownership/responsibilities are clearly understood.
- 2 Definition of a project charter with clearly defined roles and responsibilities within the organisation. To be defined at the beginning of the project and to include consultants and implementation agencies as and when they are appointed.
- 3 Development of communication plan to be rolled out from the conception of the project and updated through varied media such as newsletters during the life cycle of the project. The objective being to promote the benefits of the project and maintain buy-in from stakeholders. Justification: Continuous positive communication ensures stakeholders value the project and their own tasks.

Part A GIS (NEW)

- 1 All GIS functions to be separated from the main IT package to ensure that they attract special focus. Justification: All projects have experienced difficulty in this area, GIS is a keystone to all other tasks and also requires specialist skills.

Part A IT (REVISED)

- 1 As existing IT package without GIS and AMR. This package would now focus on Business Processes and would require close coordination with implementation of GIS and AMR as well as operational applications. (See Section 3 Part A integrated operations).

Part A Operational Applications Strengthening OAS (NEW)

- 1 Includes SCADA DMS but with an additional Network Planning Tool as per the requirements of the ISGF roadmap for advanced distribution.
- 2 Now to include OMS as per the requirements of the ISGF roadmap for advanced distribution.
- 3 Now to include Condition Monitoring for DTs as per the requirements of the ISGF roadmap for advanced distribution.

Part A Integrated Operations (NEW)

- 1 Integration of GIS with all applications including SCADA this is not clearly defined in the current R-APDRP scope.
- 2 Integration of AMR with all applications.
- 3 Integration of Condition Monitoring with Workforce and Asset Management as per the requirements of the ISGF roadmap for advanced distribution.
- 4 Integration with ERP (minimum HR & Finance) as per the requirements of the ISGF roadmap for advanced distribution.

Part B Planning (NEW as per Part A planning)

- 1 Structure of Core Team at a central level and field (town) level for ownership and implementation of the project. To be started from day 1 of conception of the project.
- 2 Definition of a project charter with clearly defined roles and responsibilities within the organisation. To be defined at the beginning of the project and to include consultants and implementation agencies as and when they are appointed.
- 3 Development of communication to be rolled out from the conception of the project and updated through varied media such as newsletters during the life cycle of the project. The objective being to promote the benefits of the project and maintain buy-in from stakeholders.

Part B Distribution Network Strengthening (REVISED)

- 1 Modernisation of remaining 11kV Substations and Modernization of all 110/132 33 kV and above: GIS where ever feasible, new breakers, numerical relays, bay controllers transformer monitors (close coordination with part A Operations strengthening)
- 2 Scope remains the same except "SCADA Ready RMU, Sectionlisers, Auto-Reclosers and FPI" is relocated to next section. (Requires close coordination with part A Operations strengthening)

Part B Distribution Automation and Control (NEW)

- 1 SCADA Ready RMUs including: Sectionalisers, Auto Reclosures, FPI and FLISR.
Justification: This section is now completely focussed on grid automation and requires specific skills and coordination between engineering and SCADA/Automation teams.
- 2 Substation Automation as per the requirements of the ISGF roadmap for advanced distribution.
- 3 Integrated Volt/VAr Control as per the requirements of the ISGF roadmap for advanced distribution.

Part B Metering & Communication Strengthening (NEW)

- 1 AMR for all DTs and Feeders relocated from original Part A IT scope. This section is now completely focussed on Metering & Communication and requires specific skills and coordination between engineering and IT teams.
- 2 AMI for all customers with loads >20 kW as per the requirements of the ISGF roadmap for advanced distribution.
- 3 Fiber connectivity for all substations 33kV and above (fiber network connecting 250K Panchayats to be leveraged) as per the requirements of the ISGF roadmap for advanced distribution.
- 5 Smart or Smart Ready Meters for all new connections as per the requirements of the ISGF roadmap for advanced distribution.

Part C Training & Capacity Building (REVISED)

- 1 Training needs and capacity building assessment to be carried out at project conception. DPR preparation to be lead by HR and loan applied for to cover costs.
- 2 Strategy for Business Process Change Management including communication plan to be developed at project conception. DPR preparation to be lead by HR and loan applied for to cover costs.
- 3 Further specific product training for applications such as GIS, AMR, SCADA etc. (see section on capacity building).
- 4 Basic IT training for all stakeholders involved in the project.
- 5 Utility induction training for all implementation agency project workers.

Revised Implementation and Monitoring Model

Based on the output from step 1 and 2 a revised implementation model has been structured. This includes the scope revisions as mentioned in the above sections, revised timelines based on field experiences, a method for project monitoring extracted from projects of similar scale, complexity and business orientation, a suggested structure for core utility teams including possible new positions and minimum skills and training requirements for the core teams.

Scope and Timeline Revision

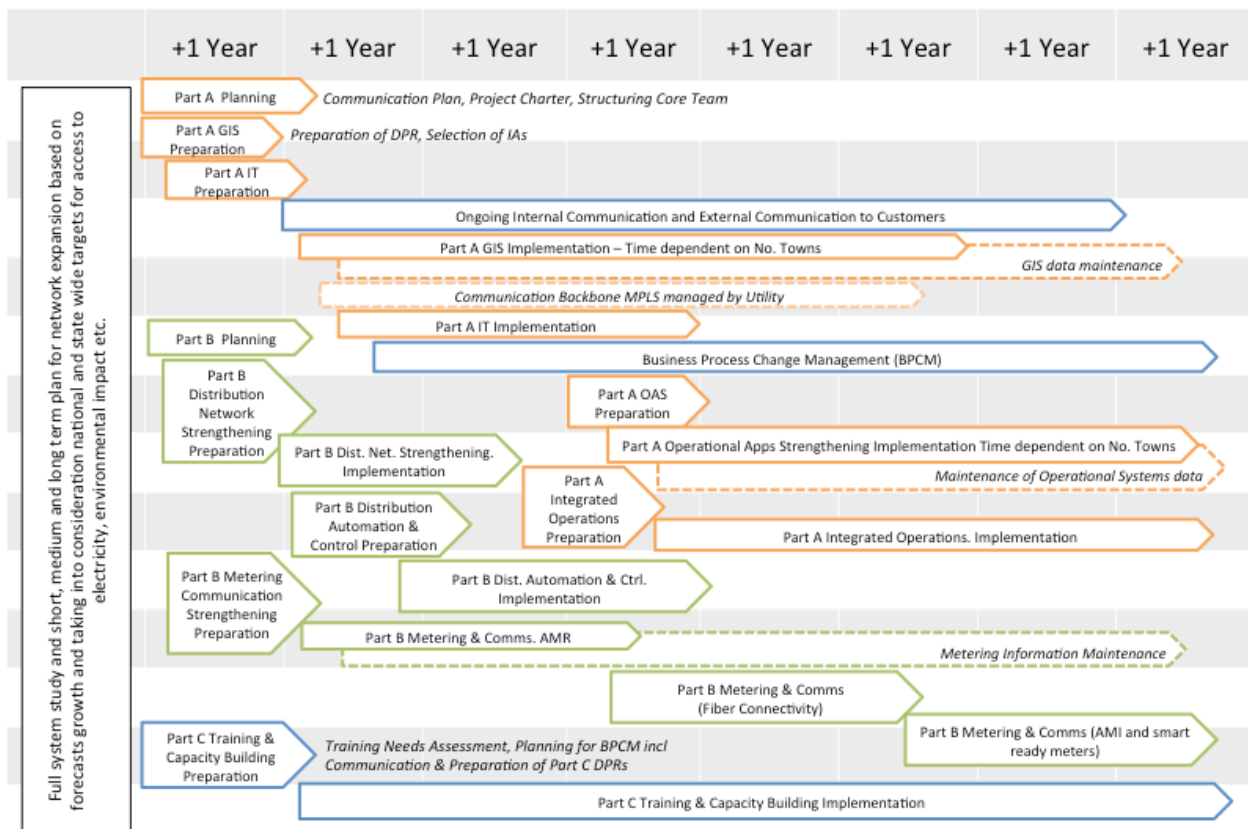
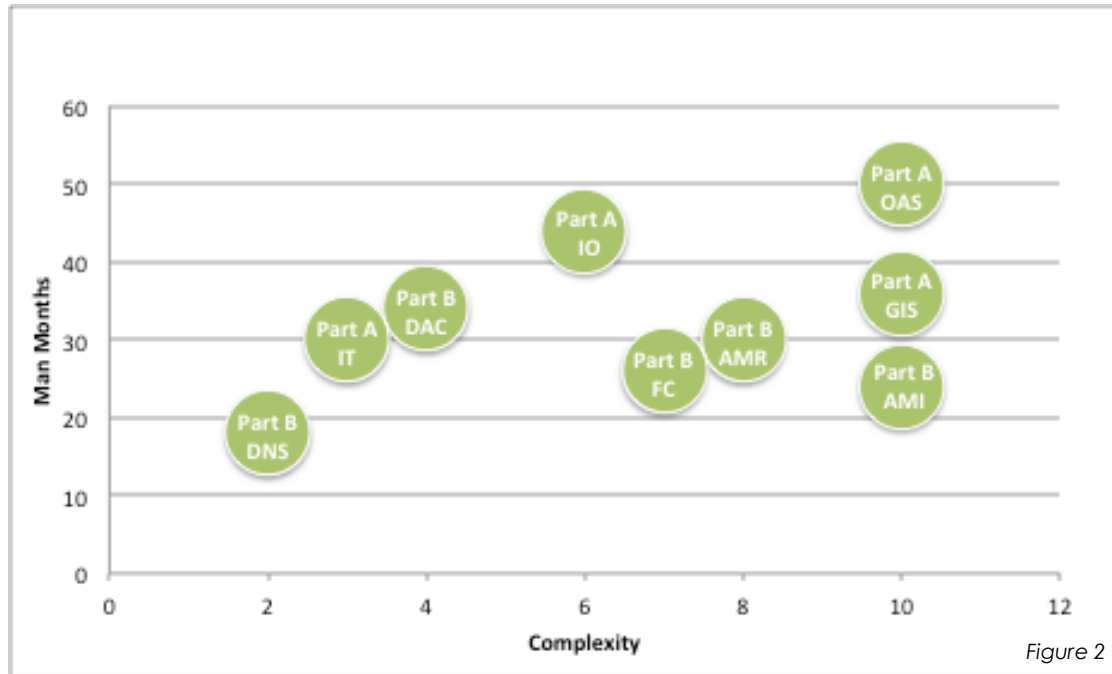


Figure 1

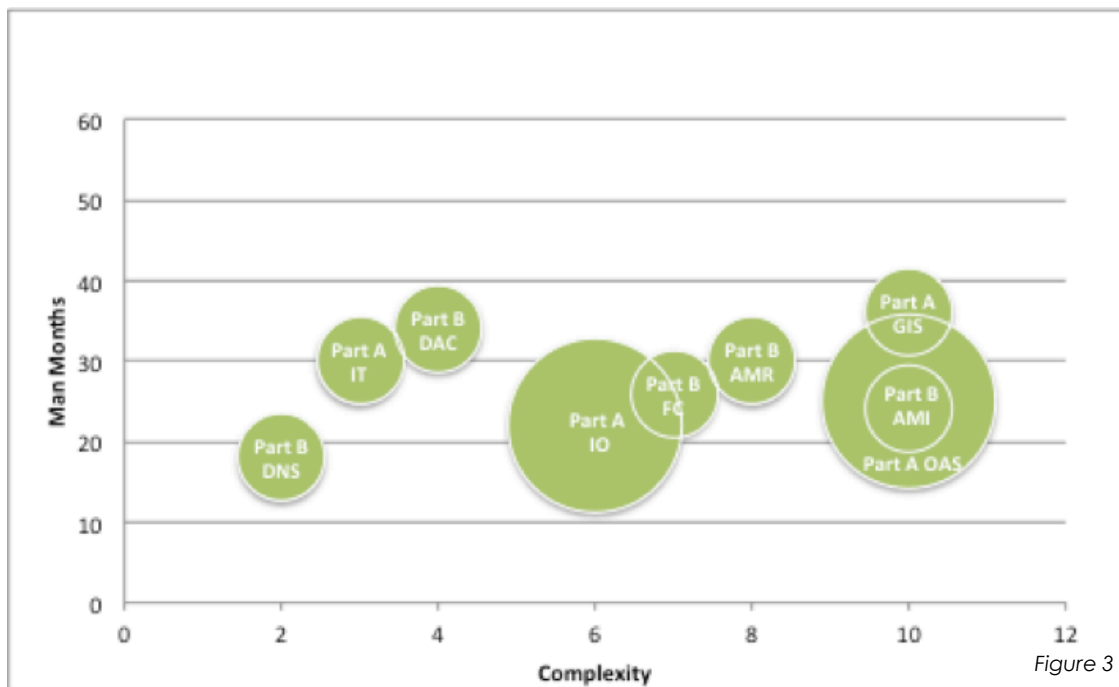
The above timelines are based on experiences in the field related to the current manpower allocated to projects.

These timelines could of course be reduced if more manpower was allocated to the more complex projects. Of course this would also entail further cost but would bring about business efficiency in a much shorter time frame.

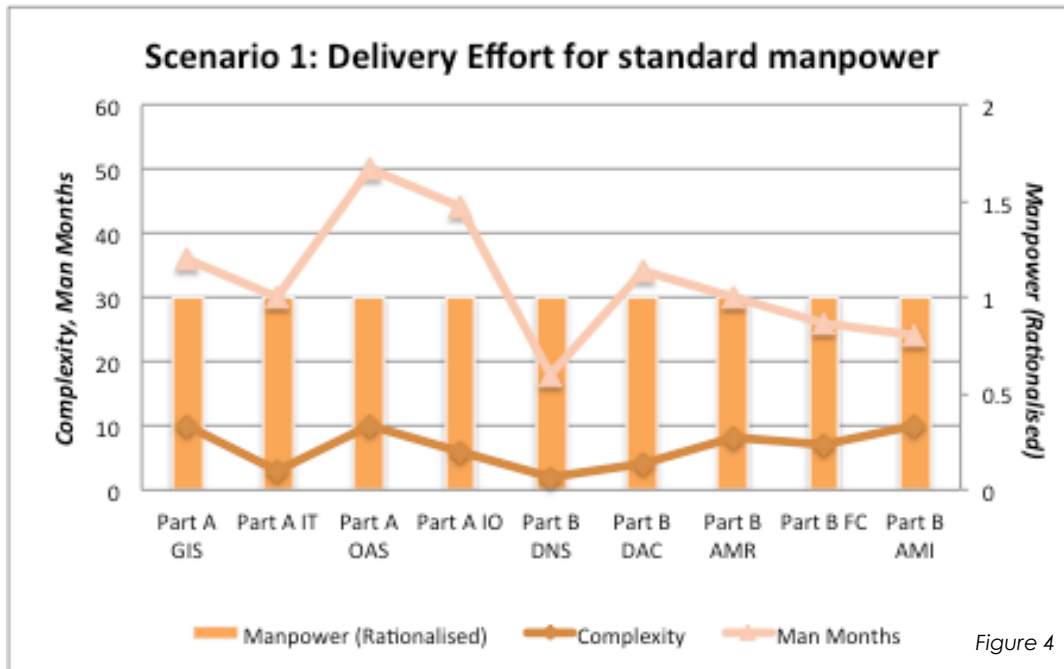
The diagram below shows the As-Is situation in terms of current manpower. The manpower status has been rationalised to 1 representing the current scenario and the positioning of the bubbles represent the delivery time in man months on the y-axis and complexity on the x-axis.



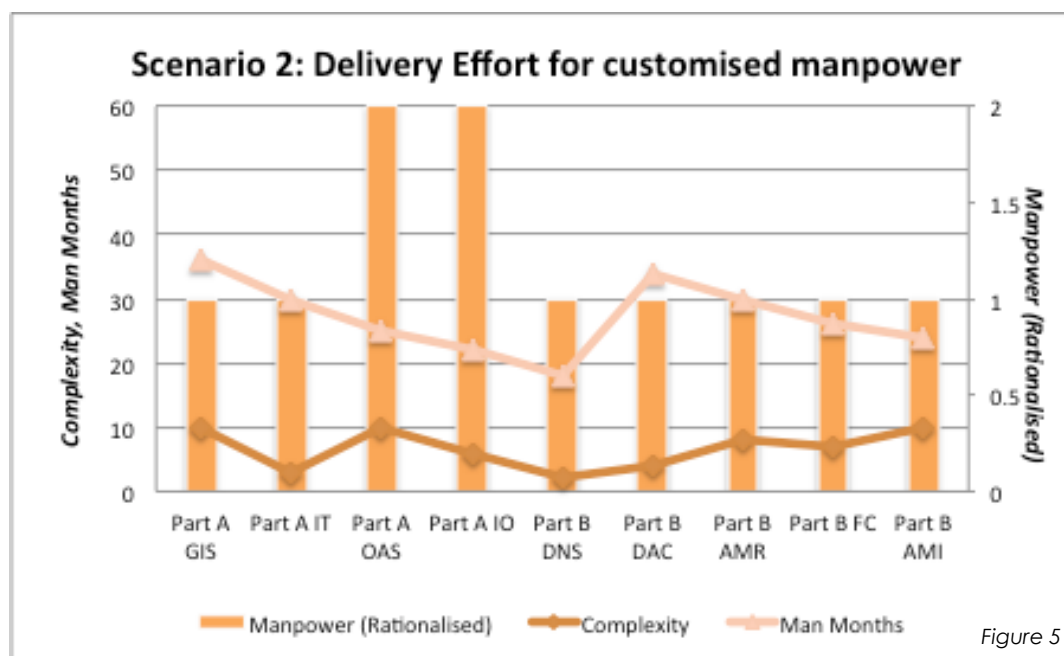
The diagram below now shows the impact on delivery (man months) and the 'outliers' if the manpower is increased (size of the bubbles).



The next diagram shows the same As-Is situation but you can see the outliers in terms of delivery time (man months) on the LH scale and complexity (ration 1:10 with 10 being the most complex) on the RH scale, whilst the manpower remains constant.



The diagram below now shows the impact on delivery (man months) and the 'outliers' if the manpower is increased (size of the bubbles) and it is evident that by allocating more manpower to the most complex projects then the outliers are better controlled and the delivery of the whole project can be managed in a certain time frame.



Project Monitoring:

Project monitoring is a key aspect to ensure the success of the R-APRDP program. The objective of this proposal is to emphasize the need for monitoring at:

- The project level specific to a utility.
- The national level generic to all the utilities and R-APRDP program.

This document proposes recommendation for creating the appropriate organisational structure and processes to meet the goals and objectives of the program at the utility level and national level.

Monitoring Methodology - National (Programme) Level

To ensure the overall success of the R-APRDP program at various utilities, it is recommended to have an R-APRDP Program governance council at a National Level. The charter of this agency includes:

- Overall governance for the entire R-APRDP program at National Level.
- Ensure that the RAPRDP programme guidelines are strictly adhered to by the utilities.
- Provide sufficient guidance and support to the utilities to execute the RAPRDP projects successfully.
- Promote best practices across the utilities.

The council should be headed by a non-government industry expert who has a track record of delivering large scale infrastructure projects/systems, and/or, have the experience of successfully managing large scale programmes involving multi-disciplinary agencies.

Experts from the following industry organisations should be chosen to represent the governance council:

1. MoP
2. Regulator
3. CEA for Standards
4. Utility
5. ITIA/SI
6. TPIEA
7. Equipment OEM
8. Finance

Project Monitoring Methodology - Utility (Project) Level

The following diagram describes the recommended organisation to be formed at the Utility level. The project team(s) are to be governed by a management committee with the ultimate responsibility lying with the chairman of that committee.

The diagrams below shows the project teams to be formed at central and field (town) levels:

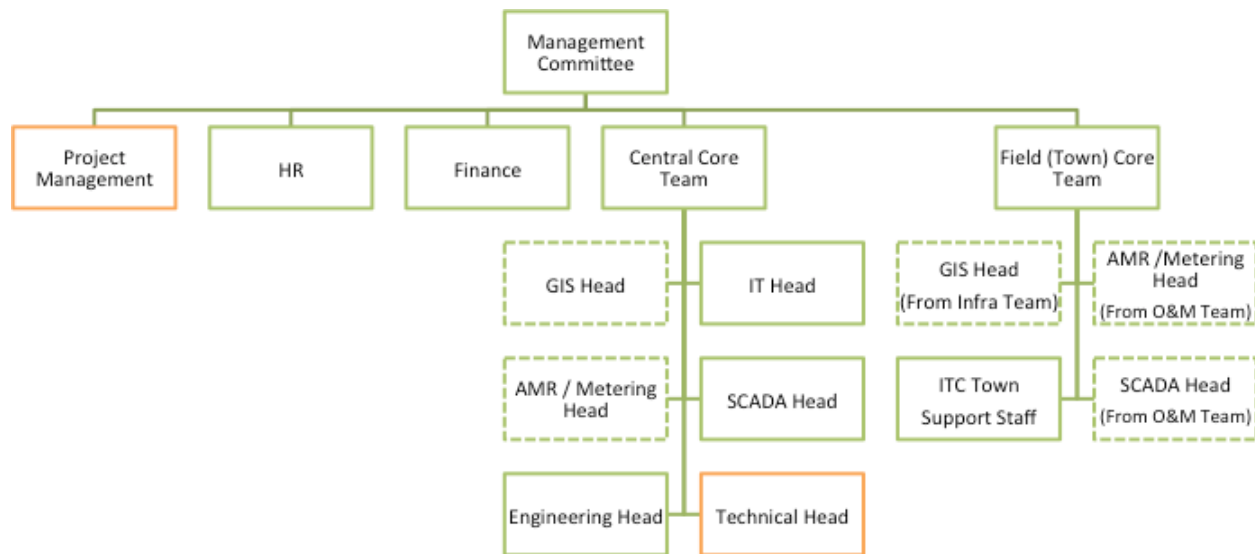


Figure 6

The utility/project owner should form a multidisciplinary Core Team. This team consists of representatives from the various key areas (IT, GIS, Engineering, Metering, Automation, HR, Finance, Quality etc.) to anchor the project in their respective area. The core team members report directly to the management committee.

As well as a core team the utility should form a Project Management Office (PMO). An internal/external expert should be chosen to head the PMO. The Project Management Head, reports in to the management committee.

The role of the Project Management Head is to manage the overall project with end-to-end delivery focus. All the project managers, from the external agencies, involved in the project execution, report in to the Project Management Head. The responsibilities of the Project Management Head include the following:

- Overall project delivery and accountability
- Project Planning – ownership of the project master plan
- Monitoring and Control
- Risk identification and mitigation
- Periodically communicate the project status, including project metrics, to the Project Owner and stakeholders in the management team
- Coordination between various project managers representing the external agencies, internal core team and technical experts.
- Change management.

Finally the utility should form a Technical Team. Ideally, if possible this team should be internal to the utility and consist of domain/subject matter experts from various disciplines including the following:

- GIS/Network Planning
- IT – Hardware
- IT – Software
- Utility business process experts (CRM, ERP, CIS, Asset Management, etc.)
- Outage Management
- SCADA/DMS/Network Planning
- Network Communication/Network Management/ Network Planning
- Field Operations
- Customer Service Support
- Electrical Equipment
- Finance
- HR
- Quality/EHS
- Operation & Maintenance
- Etc.

A qualified Technical Expert is chosen to head this team. The members of this team could be working either full time or part time on the project with specific goals & objectives. The members of the team virtually report in to the Technical Head. This team plays a critical role in ensuring that the technical requirements of the project fulfilled. Some of the team members could be also part of the core team. The responsibility of this team includes the following:

- Identify the project objectives for each domain and set the targets accordingly.
- Conduct technical reviews during the various stages of the project.
- Ensure that the business process workflows are implemented as per the utility requirements.
- Ensure that technical deliverables under the responsibility of external agencies meet the Critical To Quality (CTQ) objectives.
- Understand the Operation and Maintenance aspects of the system and provide guidance to the implementation team during the various stages of the project.
- Enquire into consumer welfare and the overall value proposition.

The structure and responsibilities are detailed in the diagram below:

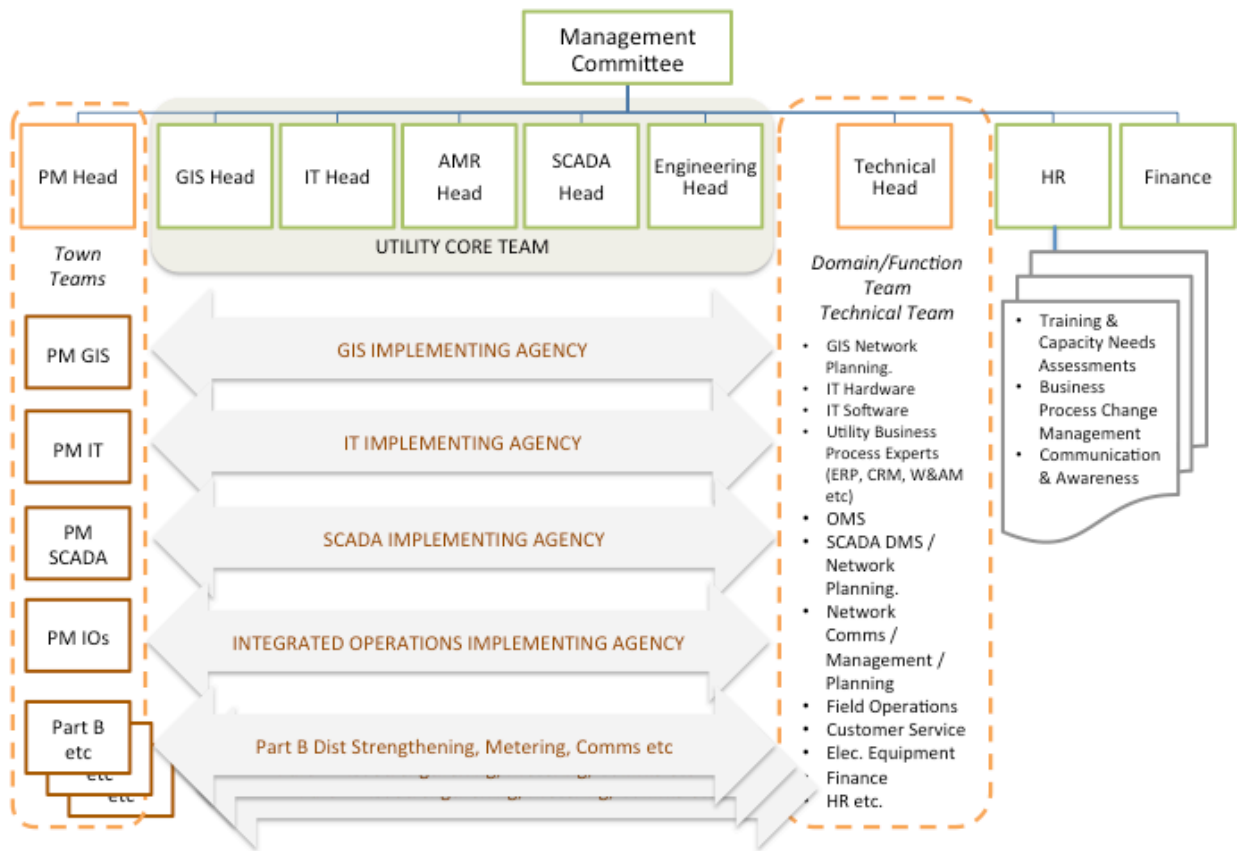


Figure 7

R-APRDP – Implementation Process Model

To successfully implement the RAPRDP project, the process model, described on the next page, is proposed. The objective of the model is to provide sufficient checkpoints to fine-tune the implementation iteratively.

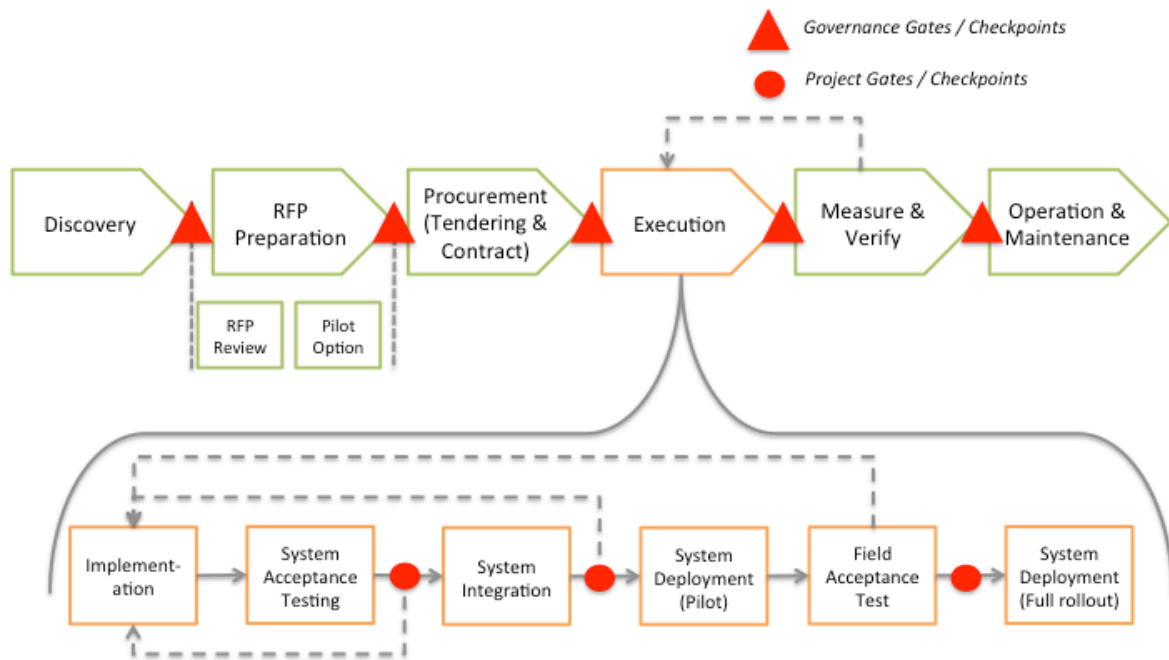


Figure 8

The process model consists of several stages and sub-stages. Since the project is complex, the objective is to approach the project in an incremental way. At the end of each stage, the RAPRDP governance council should review the project status, and utility's readiness to move into the next stage.

Notes on checkpoints:

- Defined measurable KPIs based on experiences in states.
- Should be different to specification and should be in line with operational requirement of utility.
- Should be reported and monitored during management committee review meeting.

The stages in this model are described below.

Discovery Stage: (Approx. 3 Months.)

The objective of this stage is to do a thorough analysis of the current implementation and document the "As Is" state. The PMO along with the project core team and project technical team, consisting of interdisciplinary SMEs, should critically review the R-APRDP program. The DPR prepared by the Utility is a key input for this review.

The deliverables of this stage are:

- Current “As Is” State and Desired “To Be” State
- Global System Architecture
- System Dependencies
- Deployment Strategy
- Financials
- Business Process Standardisation Plan
- Project Roadmap with Milestones

RFP Preparation Stage: (Approx. 3 Months.)

There are two sub stages, RFP review stage and an optional pilot stage, in this stage. The objective of RFP review stage is to develop detailed system specifications that can be tendered. The Project team should perform gap analysis to meet the “To Be” state. In the Optional Pilot stage, if required, the utilities should use one of the current implementation sites to validate the requirements and identifying gaps.

The deliverables of this stage are:

- Detailed specifications and system level use cases
- GAP Analysis
- Software/Hardware/Communication plan
- Tenderable RFP
- System deployment readiness and utility readiness
- Resource and training plan
- Terms and conditions

Procurement Stage:

In this stage, the utility enters into the contract/bid negotiation with various empaneled agencies and identifies the agencies that can meet the requirements.

Execution Stage:

This stage, the utility along with the selected agencies starts the system implementation. Before the final rollout, the project is executed in an iterative manner.

Measure and Verify Stage:

In this stage, the utility monitors the system as per the RAPRDP guidelines and measures the AT&C loss and other Critical To Quality (CTQ) parameters.

Operations and Maintenance:

The Utility continuously manages and maintains the system at this stage. Based on the utility's roadmap, next level enhancements are made to the system as and when needed.

Recommendations: Changes to specifications & Guidelines

The recommendations detailed in this part of the report are in some part as a result of interviews with stakeholders but mainly they are collective inputs from experts such as OEMs, IT service providers and trade organisations which have been collated and rationalised expert members of the project team.

Every effort has been made to ensure that the specifications: are fit for purpose, are vendor neutral, they comply with current standards and are therefore current and even 'future proof', they leave some flexibility in terms of sizing which can be decided at the time of DPR and they promote efficiency.

The specifications reviewed are the SRS for Part A IT and the MTS for part A SCADA. Also some small recommendations have been made for a minimum standard for Part B. The specifications for the products and applications included as part of the revised scope are aligned with the vision of the ISGF roadmap for advanced distribution has not been reviewed. However in the final section of this report there are some indications of the standards to which they should comply and recommendations on further research that could be carried out by the ISGF expert working groups.

One further recommendation is that a further detailed review of specifications should be carried out including a gap analysis of the existing versus the future requirements of the ISGF roadmap for advanced distribution in the 12th, 13th and even 14th Plan as there may be work that could be done now especially in terms of communication protocols etc. that could ease the way towards the smart grids of the future.

Whilst this report hasn't reviewed the specification for metering in detail as this work is being managed by an expert group within ISGF. A major issue for consideration would be to ensure that equipment being implemented today should not become unusable in the future e.g. equipment which is not Smart/Smart-amenable. E.g., no GSM modem should be allowed. All modems should be data-centric, ideally 3G (backwards compatible to edge and GPRS). Similarly, meters shouldn't be limited in what they record (time-blocks) but flexible/programmable. Importantly, the concept of a concentrator/aggregator, which can facilitate LT metering, DT monitoring, etc. may be important.

R-APDRP Part A IT G1 Specifications

EXISTING	RECOMMENDED CHANGES
1 Section 3. Scope of work	<p><u>Gap analysis of existing IT Infrastructure</u> should be part of the scope.</p> <p>This is required to be performed by, either the Utility owner or vendor, to assess the state of legacy IT infrastructure, before planning for strengthening the IT infrastructure. This may be all the more important if the same IT setup has to be strengthened for future Smart Grid needs.</p>
2 Section 3. Scope of work	<p><u>Assessment of utility business processes and standardisation plan</u></p> <p>The vendor in collaboration with the Utility should understand the Utility specific Business Process, workflows and related dependencies. The vendor should elaborate the use cases in the business process and identify the plan for standardising the business process.</p>
3 Section 3. Scope of work	<p><u>System component architecture and roadmap</u></p> <p>A comprehensive high-level system wide roadmap should be prepared. The architecture should depict dependencies between various systems/sub-system components. The Roadmap should provide details on when the system components will be made available.</p>
4 Section 4. Other Services and Items	<p><u>Detailed master project plan for the entire project</u></p> <p>The plan should roll up all other project plans provided by the vendors participating in the project in their respective areas. The master project plan should call out the risks, dependencies, vendor specific delivery milestones.</p>

R-APDRP Part A IT G1 Specifications (continued)

		<u>System deployment and integration strategy</u>
5	Section 4. Other Services and Items	Since there are several systems and sub systems, it is important to understand the details of when, what order and how the various components in the system will be rolled out and integrated with each other.

R-APDRP Part A IT G2 Specifications

EXISTING		RECOMMENDED CHANGES
1	Section - Sf.9 / Sf.23	Should include CIM 61968, Multi speak, and similar related standards for domain specific information exchange
2	Section - Sf.11	Looking at data volume and real time analytics for decision support, distributed database (network based database system) along with Complex event processing (CEP) technology should also be considered.
3	Section - Sf.13	The model for maintaining distributed databases at a local database at a Subdivision level would increase the complexity of synchronising and managing the data. The database at the subdivision vision should be lightweight and should in near-real time pass on the data to the central system, which maintains the master data. The subdivision systems should store the data for a longer duration only when there is connectivity issue with the central system.

R-APDRP Part A IT G2 Specifications (continued)

4 Section Sf. 31

The technology mentioned is restrictive to RDBMS. Considering the evolution of the new database technologies (example time series database, etc.), the specification should be open to adopt any standard database technology that matches the performance needs of the system.

R-APDRP solution architecture would benefit from the inclusion of a 'data historian' or similar database technology for long-term storage, analysis and integration of data from real time systems viz SCADA, DMS, AML, etc. The current ISR specified in the SCADA scope of the model specifies essentially an RDBMS based short-term storage of SCADA data for operator usage. A separate data historian built on real-time database technology offering long-term storage would be effective in integrating real time operational data with business applications viz billing, CIS, Asset Management, etc.

5

**1.0 Module: Meter
Data acquisition
System**

1. Communication technologies should not be restrictive. It should be IP based and include all transportation technologies such as: RF, PLC, DSL, Wi-Fi, Wi-Max, LTE etc. that can be used in a viable manner.

2. The Data logger can be a PC or Data Collector or Data Concentrator Unit (DCU) so that cost effective equipment can be used.

3. Consolidation from various data acquisition server (PC / DC / DCU) can be done using MPLS / VPN / GPRS by both push (scheduled) and pull (on demand) mode on incremental basis.

4. Restrictive clauses like, 'no storage', 'no data collection' unless initiated by server should be removed. With current encryption technologies data can be secure and performance can be improved if such clauses not restrictive.

5. Communication ports should not be restrictive. They should include all technologies such as RS485, RS232, RJ11 or any suitable internal/external standards based technology.

6. In addition to the option for logging and generating spreadsheets, the system should be capable of providing standard web service interface for monitoring and streaming alerts and events to any external system interfacing with MDAS.

7. MDAS Activities/tasks should be appropriately classified (For e.g. Lot of NA/GIS related requirements listed under MDAS) - Network Upgrade actions, Virtual Metering Nodes etc. are not really part of MDAS, and should be part of NA/GIS.

6	Module 1.0 – Das 1.4	Ideally, in a smart grid world, the role of MDAS is mainly to collect the data in an efficient and scalable way. The optimal use of data is within the context of the Meter Data Management system and Billing information System.
7	Module 1.0 – Das 1.5	It is not clear whether the decision support system is part of MDAS or not. Usually, such systems should be part of the business intelligent (BI) applications outside the context of MDAS. These systems interact with MDAS using standardised interfaces.
8	Module 1.0 – Das 1.6	This specification is overlapping the MDM/BI applications/systems. Considering future smart grid scalability needs of MDAS, any such overlapping specification should be excluded from the MDAS, and should be part of the MDM/BI applications/system.
9	Module 1.0 – Das 1.8	For future Smart Grid support, Asset monitoring should be a separate application outside the context of MDAS. The Asset management system should interact with MDAS using standardised interfaces.
10	Module 1.0 – Das 1.11	Event notification can be via individual / group SMS, or e-mail.
11	Module 1.0 – Das 5.1	The system should have the ability to use incremental poll or push mechanism to collect the data.

R-APDRP Part A IT G2 Specifications (continued)

- | | | |
|----|--------------------------|---|
| 12 | Module 1.0 –
Das 5.2 | <p>The concept of multiple data collection systems can be compared to Data concentrators/collectors in an AMI/Smart Grid system.</p> <p>The Data logger can be a PC or Data Collector or Data Concentrator Unit (DCU) so that cost effective equipment can be used.</p> <p>The database at the subdivision Office should be lightweight, and this system should in near-real time send the data to the MDAS, which maintains the data in a centralized database. The Subdivision systems should locally store the data for a longer duration only when there is connectivity issue with the central system.</p> |
| 13 | Module 1.0 –
Das 5.6 | <p>The manual option should be eliminated. Instead the specification should focus on remote tools that enable the user to automatically configure the modems and communication modules in the meter. The tool should also have provision/interface for extracting the data.</p> |
| 14 | Module 1.0 –
Das 6.11 | <p>The specification should also support Web Services for importing and exporting meter data.</p> |
| 15 | Module 1.0 –
Das 6.12 | <p>The specification should support both set and time Sync functionality, so that appropriate method can be used.</p> |
| 16 | Module 1.0 –
Das 7.0 | <p>The MDAS should have mechanism to export the Network Topology via standard protocols/interfaces to a Network Management System.</p> |
| 17 | Module 1.0 –
Das 7.1 | <p>Functionality for Importing/exporting utility available Geographical area / Hierarchy information through a standard interface (Excel, Web Services, etc.) needs to be added.</p> |
| 18 | Module 1.0 –
Das 7.2 | <p>Facility to manage electrical topology (edit / delete) needs to be added for reflecting changes done in field for electrical connectivity.</p> |

R-APDRP Part A IT G2 Specifications (continued)

19

Module 1.0 –
Das 8.0

The methodology of Validation, Estimation and Editing (VEE) - is repeatedly undergoing changes and this methodology is not consistent across DISCOM/Utilities. The VEE methodology should be standardised.

The Meter Data Management functionalities like VEE, etc. should be decoupled from the MDAS, to enable MDAS to meet the scalability and data processing needs of AMI/Smart Grid system. Including the VEE in MDAS creates overlap between the MDAS and MDM. This also restricts the use of integrating the MDAS with any standard MDM systems available in the market.

Some of the Data Analytics specifications in the MDAS are overlapping with MDM functionality. These specifications should be decoupled from MDAS and included into a MDM specification.

20

Module 1.0 –
Das 11.7.7

In addition to MS Excel, the specification should allow the use of any standard reporting format.

21

Module 1.0 -
Das.13.0

Both time set and time Sync functionality needs to be included so that appropriate method can be used. 1mS resolution may not be required for meters

R-APDRP Part A IT G2 Specifications (continued)

22

Module 1.0 - Das –
Gaps
(Specifications
required for
supporting future
AMI/Smart Grid
needs)

MDAS Should have the ability to:

- Remotely, and securely, Over the Air (OTA), upgrade the firmware of Meters, communication modules and Home Area Networking (HAN) modules.
- Remotely upload/configure the Tariffs to the meter.
- Remotely program the HAN Smart Energy profile on the HAN module.
- Be scalable to support several millions of metering endpoints, HAN devices
- Remotely control the load for a group of devices
- Broadcast or group-cast the Demand Response (DR) events and Real Time Pricing signals.
- Act as a portal for Personal Energy management applications and SCADA/DA application using the same communication networks.
- Support strong standards based (NIST or STIP) security.

Looking at data volume and real time data analytics requirements, the specification should be flexible to adopt columnar/distributed database with complex event processing (CEP) & real time Analytics technologies for minimising the data transfer latency and achieve inflight data analytics and efficient decision support system.

23

Module 1.0 – Das -
Generic

The SRS doesn't provide clarity on the ownership of master Data. It is recommended that the Utility Customer Information System maintains the master data.

The MDAS derives the data required for Data Collection from MDM, which in turn derives the data from the master database. Das7.9, Das7.10, Das7.11 should be part of GIS

Das4.4 mentions "Synchronise date and time of all meters". This may not be always possible, **as API provided by meter manufacturers may not allow for the meter time to be changed.**

R-APDRP Part A IT G2 Specifications (continued)

24

Module 2 - Energy Audit

Energy Audit component/subsystem should have clearly defined standard interfaces to other subsystems (MDAS, MDM, Asset management, Billing & Collection, CIS, etc.) to orchestrate Energy Audit application.

Ea.3 mentions "Calculation of Bus bar and transformation losses in the substation". This is not possible, as SRS doesn't have any provision for metering at bus bar or power transformer except for sub-stations with SCADA.

25

Module 3 – New Connection

Keeping in mind the voluminous amount work involved, during new connection in a Smart Grid system, there should be mechanisms to automatically register the smart metering endpoint/device, remotely from the network and link it to the customer information record.

The workflows of New Connection (and Disconnection) should be integrated with an automated Work Order Management (WOM) or Work Force Management system to automate the workflows and minimise the human intervention that results in manual errors.

26

Module 4: - Disconnection & Dismantling

Dis 4 mentions "System should also have provisions for maintaining (Adding/Updating/Deleting) non-disconnection reasons to designated persons". This sentence should be removed from the SRS because in order to maintain integrity of the system, any non-disconnection reasons added, cannot be updated from front end. It should happen through a workflow.

The functionality described Disconnection and dismantling (and New Connection) are specific to Customer Information System (CIS). For future smart grid needs, we need a CIS system with clear interfaces to the MDAS and other enterprise applications in the Utility's back office.

R-APDRP Part A IT G2 Specifications (continued)

27

Module 5: GIS
based customer
Indexing and asset
mapping

The current sets of parameters in the GIS survey are too broad and include several non-utility specific parameters. The GIS survey should focus on relevant Utility specific parameters only.

Methodology for survey is not prescribed in the SRS. The survey should make use of automated tools to capture the GIS data and synchronise with the centralized system, thereby eliminating manual errors.

Some of the GIS software requirements overlap with standard Customer Information System, Asset Management, etc. To support future smart grid needs, these requirements should be delinked from GIS and should be defined to be part of respective components like (CIS, Asset management, etc.). The data ownership of each of these components should be clearly defined to ensure that there is minimal or no overlap.

In Section G3, some of the technologies mentioned like (OLE, CASE tools, etc.) are very restrictive. The system should have the ability to use the latest and greatest standardised technology that is widely supported in the marketplace.

It is not necessary that GIS images should be only 6 months old. Not many changes take place in terms of area development. GIS images that are less than 18 months or 2 years would be sufficient and less costly.

28

Module 8: MIS

The SRS should address the segregation of Operational and Management reports to ensure that the Utility personnel optimally use the reports.

The MIS requirements are very brief and could be misinterpreted easily, leading to various subsystems like analytics etc. implementing portions of MIS.

The requirements for DMS are overlapping with MIS and other components like new connections, asset management etc.

The DMS requirements should be collated and grouped to be part of a single DMS component that integrates with the rest of the system through standard interfaces.

R-APDRP Part A IT G2 Specifications (continued)

29

Module 10: Identity
and Access
Management
System

Review of standardised software applications. Sometimes the application is too complex for the job. E.g. 5 screens could be used instead of 10 for change management. **Also the rupee symbol is not available in many applications and field staffs are not aware of 'INR'.**

30

Module 15:
Collections

C13 mentions "The system should have provision for:

- i) Automatic creation of books of accounts based on: Balance Sheet and Profit & Loss Statement as per GAAP and Indian Companies Act 1956 - Annual Revenue Requirement, based on Electricity Act 2003 read in conjunction with SERC regulations
- ii) Meter to be treated as asset in ARR (may be treated as consumable material in other books of accounts)".

These are features of typical financial accounting systems but accounting system is not part of SRS; This dependency should be removed from SRS.

31

SRS General

The GIS implementation should be rolled out in an incremental way. The prerequisites (like CIS, etc.) for GIS roll out should be implemented first before integrating GIS components in the system.

Though SRS provides a good and comprehensive set of system level features but while translating these features into end-to-end business processes, Utilities are trying to fit SRS into their existing processes without reengineering. This is leading to complex workflows with lot of redundant steps creeping into the new processes. Process level view of each functional area/module along with SRS would have been helpful for Utilities in adopting best in class and optimised processes.

The specification in the SRS, the way it is framed, doesn't provide clarity on the components or subsystems. The responsibilities of the system components should be clearly defined with no overlap of functionalities.

In General the requirements are open to interpretation, which results in repeated changes based on perception of each coordinating officer of Utility. For e.g. Network Upgrade action (based on what?), Poorly performing areas (criteria not specific), Reports (as per Utility needs - very open statement). Such non-customised, hazy and ambiguous requirement should be reviewed and refined to remove ambiguities.

Obtaining data from the system is too complex. Roles/hierarchy based access to information needs should be clearly be defined to make accessing of data easier.

From IT infrastructural point/software engineering point of view, SRS does not account for the challenges on acquisition, scalability and installation volume. The SRS presumes availability of data without consideration to the challenges in other components in the system, viz., meter ability to provide data at desired frequency, consistent and reliable network availability, synchronisation w.r.t. other real time activities from other modules (GIS updates, MBC module updates), etc. The SRS should be rewritten keeping in consideration the challenges mentioned above.

R-APDRP Part A IT G3 Specifications

EXISTING	RECOMMENDED CHANGES
<p>1 Hardware Specifications - IT</p>	<p>SRS for servers and routers is not accurately sized. The sizing should be left to the individual utilities.</p> <p>Data center size of 40 seats is inadequate for some states. This sizing responsibility should be owned by the utilities.</p>
<p>2 Hardware Specifications – IT - Generic</p>	<p>Specifications in some cases are too specific and do not allow for alternatives. In some cases in the way that the specification is written it means that only one vendor can meet the criteria even if the costs are higher. Specs should be more functional so that there are multiple vendor options.</p> <p>The system hardware requirements will be different for the various system components (MDAS, MDM, GIS, etc.) to meet the scalability and reliability functionality. Therefore inputs on sizing should be provided by the respective component vendors (MDAS, MDM, GIS, CIS, etc.)</p>
<p>3 Section 11: Enterprise Management System (EMS & NMS) 11.1.4 and 11.1.5 Unix and Linux Monitoring</p>	<p>There should be a report for understanding the percentages of processor activity taking place on each monitored UNIX/Linux system. This report will be helpful to check for problems such as imbalances between user and system CPU, and long CPU waits caused by I/O bottlenecks. Attributes include system name, user and system CPU, idle CPU and wait I/O.</p> <p>There should be a report for understanding the system's virtual memory, Includes swapping and paging activity. This report will be helpful to determine if system performance problems are caused by memory shortages; attributes include total virtual memory, processes in run queue, processes waiting, page faults and page reclaim.</p>
<p>4 11. 2 Network Fault Management & Network performance analysis</p>	<p>To monitor the health of the network connectivity, the system should have the ability to measure network system latency, jitters, delay (packet delay variation), packet loss, reordered packets in %, duplicated packets in %, etc.</p>

Recommendation on Architecture

Examples of high level architecture based on IEC 61968 interface reference model.

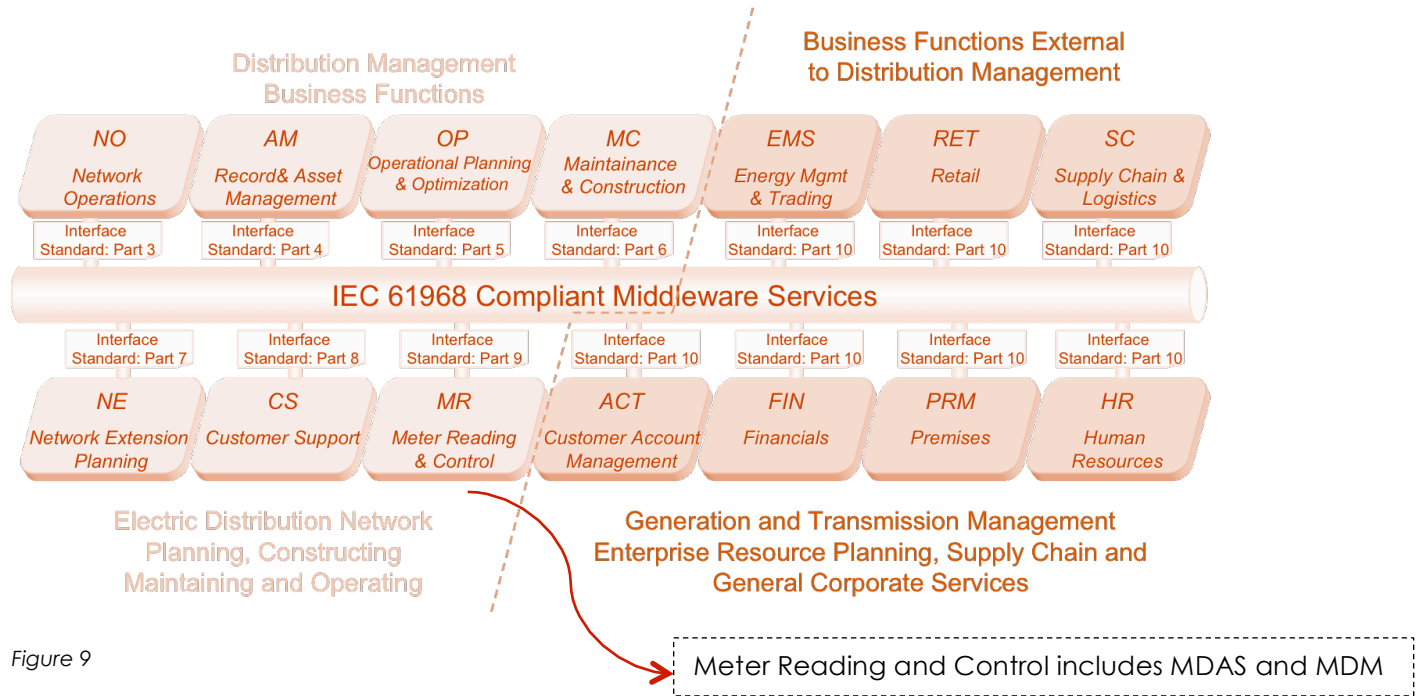


Figure 9

The following architecture describes the interactions between the Meter Reading and Control (IEC 61968-9) and other modules, as per the IEC 61968 specification

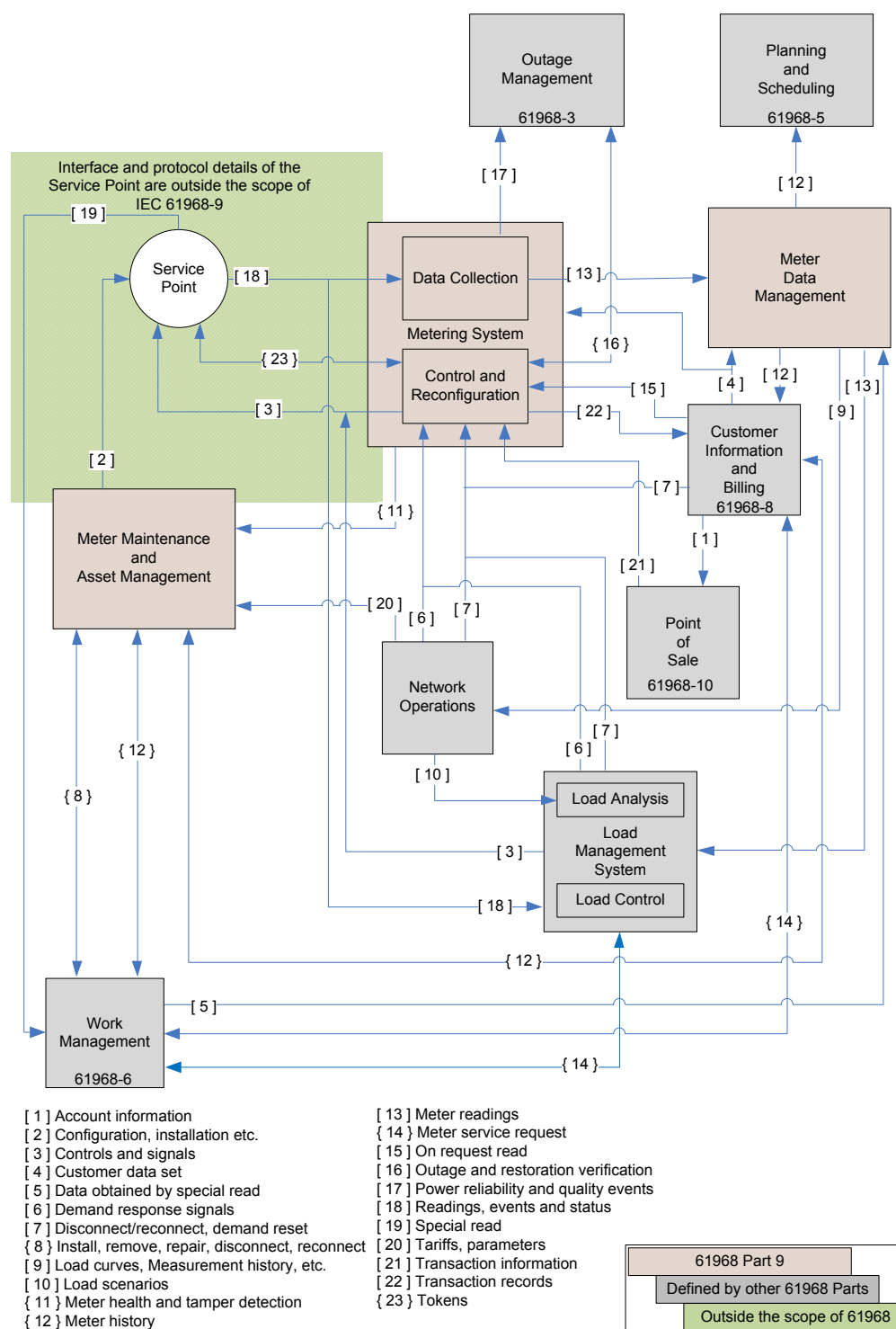


Figure 10

R-APDRP Part A SCADA MTS Specification

- | | | |
|---|---|--|
| 1 | MTS Section 2 - 1.3
Information storage and Retrieval | R-APDRP solution architecture would benefit from the inclusion of a 'data historian' for long-term storage, analysis and integration of data from real time systems viz SCADA, DMS, AML, etc. The current ISR specified in the SCADA scope of the model specifications is essentially an RDBMS based short-term storage of SCADA data for operator usage. A separate data historian built on real-time database technology offering long-term storage would be effective in integrating real time operational data with business applications viz billing, CIS, Asset Management, etc. |
|---|---|--|

- | | | |
|---|----------------------------------|--|
| 2 | MTS Section 3 - Chapter 1 | Adequate earthing for substations having any electronic equipment fitted. <0.5 |
|---|----------------------------------|--|

- | | | |
|---|--|--|
| 3 | MTS Section 3 - Chapter 2
Technical requirements of FRTU | The specs for both RTU and FRTU are the same. Consequently this spec is oversized for the FRTU. This should be rationalised. |
|---|--|--|

The DMS functions mentioned in the MTS are not adequate for the stated objective of the SCADA/DMS system. Therefore it is recommended to include the functions mentioned below to accelerate achievement of R-APDRP objectives. These functions will bring a real-time dimension to the utility's operation on the DMS software.

Whilst the list is quite exhaustive the functionality should not be limited to this list or the specific terms used as these may vary from vendor to vendor.

- | | | |
|---|--|--|
| 4 | MTS Section 2 - 2.1.1.
DMS Functions | <ol style="list-style-type: none"> 1. Performance Indicators 2. Order Management 3. Fault Calculation 4. Relay Protection 5. Energy Losses 6. Operational Losses 7. Reliability Analysis 8. Network Automation 9. Contingency/Security Assessment 10. Network Planning 11. Circuit Breaker/Fuse Capacity 12. Optimal Capacitor Placement 13. Optimal RTU / FRTU / FPI Placement 14. WEB Server 15. Outage Management System |
|---|--|--|

R-APDRP Part A SCADA MTS Specification (Continued)

5	MTS Section 2 – 2.9, 2.10 DMS Feeder Reconfiguration	Feeder/ Network Reconfiguration power function shall be used for maximal reliability & best voltage profiles in addition to loss minimisation & load balancing.
6	MTS Section 2 – 2.2 DMS Network Model	Distribution Network Model (DNM) shall be the foundation of all advanced DMS power functions, providing electrical definitions of all network elements, connectivity and models for calculation (balanced and unbalanced networks). DNM shall be designed to provide derived data, necessary for modeling the network topology
7	MTS Section 2 – 2.1.4 DMS Graphical Display	Complete network model shall be visible on the graphic display, with all network elements and objects (substations, feeders, joints etc.).
25	MTS Section 2 – 2.5 DMS – Load Flow Application	Load flow (LF) shall be executed in real-time and simulation mode. All the network's state information shall be available: Viz. complex voltages, currents, flows of active and reactive powers, voltage drops, losses etc. Load Flow input shall consist of magnitudes of voltages of network roots (HV or MV busbars of supply transformers) and loads for the considered state.
26	MTS Section 2 – Chapter 5 5.2.4 Router Specification	The router specification is defined here. No distinction is made between use at control center and at remote sites. This leads to over speciation of the device for the remote sites.

R-APDRP Part A SCADA MTS Specification (Continued)

<p>27</p> <p>Technical Requirements of RTU, 1.1, Design Standards</p>	<p>MTS Section 3</p> <p>The MTS mentions all applicable ANSI/IEC/IEEE/NEMA test in general. But it is better to be specific on the types test needs for RTU.. Viz.</p> <p>EMI/EMC IMMUNITY TESTS FOR RTU</p> <p>Surge Immunity Test as per IEC 60870-2-1</p> <p>Electrical Fast Transient Burst Test as per IEC-60870-2-1</p> <p>Damped Oscillatory Wave Test as per IEC 60870-2-1</p> <p>Electrostatic Discharge test as per IEC 60870-2-1</p> <p>Radiated Electromagnetic Field Test as per IEC 60870-2-1</p> <p>Damped Oscillatory magnetic Field Test as per IEC-60870-2-1</p> <p>Power Frequency magnetic Field Test as per IEC-60870-2-1</p> <p>INSULATION TEST FOR RTU</p> <p>Power frequency voltage withstand Test as per IEC 60870-2-1</p> <p>1.2/50 μs Impulse voltage withstand Test as per IEC 60870-2-1</p> <p>Insulation resistance test</p> <p>ENVIRONMENTAL TEST FOR RTU</p> <p>Dry heat test as per IEC60068-2-2</p> <p>Damp heat test as per IEC60068-2-3</p>
<p>28</p> <p>Technical Requirements of RTU, 1.14, Input DC Power Supply</p>	<p>MTS Section 3</p> <p>Power supplies with devices are vulnerable. Current MTS calls for Single power supply within the RTU. It is advisable to have dual power supply (with separate power input) for redundancy purpose / also dual power supply could be a complement if substation has dual power supply.</p>
<p>29</p> <p>Chapter 1, Clause 1.18</p>	<p>MTS Section 3</p> <p>Field wiring to RTU panels are supposed to be from "Control & Relay panel in the substation control room". The same clause states "Armoured cables shall be used in the area where cable will pass through open area which may experience loading". This causes confusion, as Utilities always demand that field cables run from open switchyard. This is a gross deviation from the requirement that the cables shall run from C&R panel within the substation control room, which is a protected area and should not require armoured cables. Over and above no lengths are provided for cable runs, which is the normal practice. Vendors are left to their own theoretical estimations, which lead to inaccuracies and huge cost differentials.</p>

R-APDRP Part A SCADA MTS Specification (Continued)

30 **MTS Section 3** Technical Requirements of RTU, 1.2, RTU Functions

In MTS IEC61850 protocol is specified without much mention on client or server. It is essential to be specific on these needs and also ensure conformance as per IEC61850 standard.
IEC61850 Client should be supported for Numerical Relays (which are servers by default).
Interlock logics should be possible between RTU direct points and numerical relay point on IEC61850.

31 **MTS Section 3** Technical Requirements of RTU, 2.1, Design Standards

The MTS mentions all applicable ANSI/IEC/IEEE/NEMA test in general. But it is better to be specific on the types test needs for FRTU.. Viz.
Dielectric AC voltage input IEC 60 255-4 Insulation (50 Hz/1 min): 10 kV
Surge (1.2/50 μ s): 20 kV
Toroid input IEC 60 255-4 Insulation (50 Hz/1 min): 2 kV Surge (1.2/50 μ s): 5 kV
Electromagnetic Fast transient bursts IEC 61 000-4-4 Level 4: 4 kV (mains, sensors), 2 kV (other circuits)
Electrostatic discharge IEC 61 000-4-2 Level 3: 6 kV on contact
Electric fields IEC 61 000-4-3 80 MHz to 1 GHz - 10 V/m 80 MHz to 1 GHz - 30 V/m
Radio frequency in MC IEC 61 000-4-6 0.15 MHz to 80 MHz - 10 V rms
Damped oscillatory waves IEC 61 000-4-12 2.5 kV common mode, 1 kV differential mode
Pulsed magnetic field IEC 61 000-4-9 1000 A/m peak
Surge IEC 61 000-4-5 Coupling between line wires 1 kV, between wire and frame 2 kV
50 Hz magnetic field IEC 61 000-4-8 30 A/m 100 A/m
Climatic Operating temperature -15°C to + 55°C
Relative humidity 93% at 40°C, 96 h
Salt mist IEC 60 068-2-11 192 h at 35°C 336 h at 35 °C
Storage temperature -25°C to + 70°C
Mechanical Vibrations IEC 60 068-2-6 10 to 500 Hz 1 g; 10 cycles 10 min
Protection IEC 60 529

R-APDRP Part A SCADA MTS Specification (Continued)

MTS Section 3

32 Technical
Requirements of
FRTU,
2.1, Design
Standards

FRTU as whole along with its subsystems (RTU, Battery Charger Card, Power Supply, Modems etc) should be designed and type tested for Secondary Distribution Automation as one unit. Also for field operators it is easy to handle, if the FRTU front panel arrangement could depict the real world equipment's (RMU etc,) its is monitoring/control. Also it is very essential to have a Local / remote switch on the FRTU for security reasons
Viz. 1) Looks like RMU front facia with LED or mechanical Semaphore arrangement for primary equipment Status.
2) Local Control option with look and feel of RMU front facia
3) Local / Remote control etc.,

MTS Section 3

33 Technical
Requirements of
FRTU,
2.3,
Communication
Ports

In present MTS External modems are specified. Internal modems (onboard CPU) could reduce point of failures.

34 **MTS Section 4**
Clause 4.3

The specs for DCPS for both RTU and FRTU are the same. Consequently this spec is oversized for the FRTU. This should be rationalised.

35 **MTS Section 6**
Chapter 2

FMS

This clause details 5 years of FMS. Actual tenders have seen huge variation in price of vendors towards FMS. To keep this clause meaningful and to create a level of standardization in FMS, the MTS should define a minimum level of percentage towards FMS charges.

R-APDRP Part B (currently not existing)

RECOMMENDATIONS

As a minimum BIS/IEC Standards must be specified for all key components of the network. Special care shall be taken to standardise the requirements in line with international and national standards and CEA guidelines. Particular attention to be paid to:

1. Ratings of equipment – follow standard ratings
2. Competing technologies may be considered but functionalities to be defined – e.g. SF₆ and Vacuum, stainless steel and resin cast, etc. are technology variations but minimum performance levels should be defined
3. Standardise installation interfaces – foundation layouts, connection points, etc. so that interchanges of equipment are possible
4. Divide the Country into three to four climatic zones and standardise operating conditions
5. Rationalise conductor ratings viz-a-viz current ratings so that optimum performance can be expected from equipment and life-time of equipment can be extended

Wherever possible, equipment shall be fitted with monitoring sensors/devices that not only measures operational parameters (like current and voltage), but also condition monitoring (Oil-temperature, winding temperature, etc.)

2. Low loss Transformers, optimum rated cables, and other low-loss equipment to be specified. The DPR's for part-B should be evaluated with the objectives of the project in mind – i.e.
 1. Reduction of losses – weighting 50%
 2. Reliability improvement – weighting 25 %
 3. Power quality improvement – weighting 25%

3. While various vendors and consultants have been empanelled for Parts A IT and SCADA, the same could be done for Part-B

4. Meter communication should be DLMS

5. There should be a general functional specification for Part B

6. The durability of equipment has to be fixed based on failure rate of the equipment through measurements like MTBF, LCA, etc.

R-APDRP Part B (currently not existing)

Installation standards to be specified, so that the equipment shall offer optimum performance:

- 7
1. Safety
 2. Operational efficiency
 3. Vandalism
 4. Maintainability
 5. Aesthetics

Recommendations for Process Mapping

The SRS provides a good and comprehensive set of system level features, however to ensure the full benefits of the project are realised, the SRS, which should be backed up with well laid out processes. DisComs may already have existing processes for each of these features and therefore they are currently trying to fit the SRS features into their existing processes. However it is possible that while trying to merge such processes the utility will end up having complex work flows with many redundant steps creeping into the new structure.

It is therefore felt necessary to develop a DisCom level process map during the project planning phase, which will help smoothen the entire workflow and shall not lead to any kind of duplication/exclusion of features.

The following matrix demonstrates indicative mapping of the SRS modules with Level 1 DisCom processes that would help to formulate process maps. Ideally the process maps should clearly lay down paths and roles for Levels 1,2,3 and 4, which are described further below:

Summary of Classification Taxonomy (Level 1 Processes)	SRS Modules Covered
Connection Management	Module 3.0 New Connection
Meter to Cash	Module 12.0 Commercial Database of Consumers Module 13.0 Metering Module 14.0 Billing Module 15.0 Collections
Revenue Assurance and Recovery	Module 4.0 Disconnection & Dismantling
Meter Data Acquisition and Energy Audit	Module 1.0 Meter Data Acquisition Module 2.0 Energy Audit
Customer Service	Module 7.0 Centralized Customer Care Services Module 9.0 Web Self Service
Asset Management	Module 16.0 Asset Management
Maintenance Management	Module 17.0 Maintenance Management
Other Processes	Module 8.0 Management Information System (MIS) Module 5.0 GIS based customer Indexing and asset mapping Module 6.0 GIS based integrated network analysis
Technical Processes	Module 10.0 Identity and Access Management system Module 11.0 System Security

To ensure common understating for all stakeholders, the following definition of Level 1, 2 and 3 could be used:

- **Level 1 Process Category:** Represents the highest level of process in the Utility such as New Connection, Metering, Billing Collection or Asset Management
- **Level 2 Process Group:** Indicates the next level of processes and represents a “group of processes.” Name Change, Load Change or New Connection (LT & HT) each of which are examples of a process group under New Connection Process Category.
- **Level 3 Process:** A series of interrelated activities that convert inputs into results (outputs); processes consume resources and require standards for repeatable performance; and processes respond to control systems which direct the quality, rate and cost of performance.
- **Level 4 Activity:** Indicates key activities performed when executing a process. *This level should be left to Utilities to decide based on the solution selected for implementation.*

Sample Process Catalogue:

Process Category (Level 1)	Process Group (Level 2)	Process Name in Flow Chart (Level 3)	Process description
1 Connection Management	1.1 New Connection	Applicant requests a New Connection / Change in attributes.	
		Completes web-based Application Form.	
	1.2 Load Enhancement	Applicant requests load enhancement.	
2. Meter to Cash		Accesses web self-service.	
	2.1 Meter Reading (Manual)	Generate meter-read cycle for next 'x' days	
		AMI	
	2.2 Billing	Upload meter readings and bill details.	
		Perform sanity check of meter reading and other data.	

Sample Process Map:

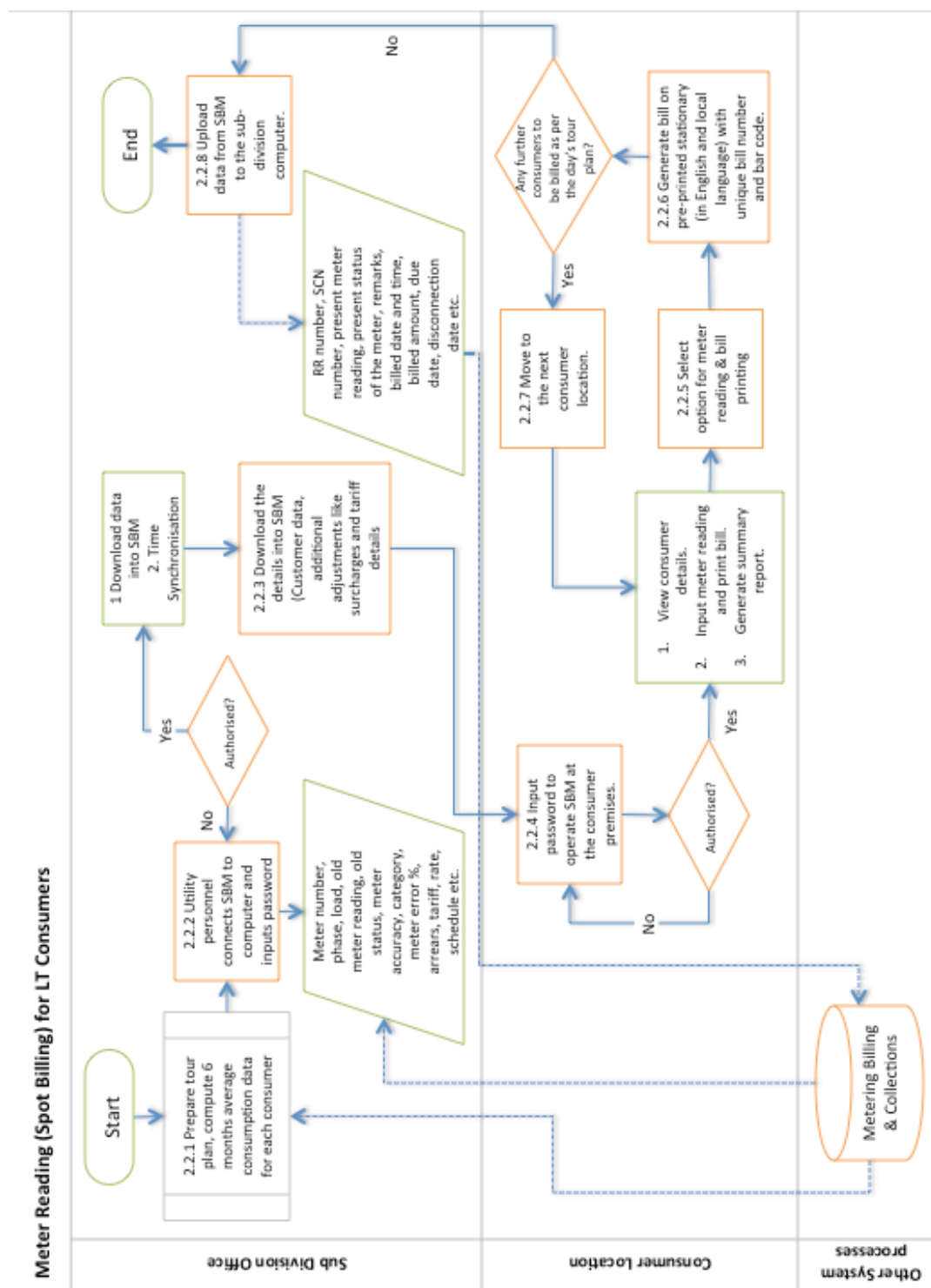


Figure 11

Analysis of Capability and Readiness to Adopt.

The overall opinion is that the utilities, consultants and implementation agencies were not ready to implement R-APDRP in terms of manpower capacity and ability. However in some states it was less of a challenge because they realised this at the project conception and immediately took action by carrying out a training and capacity building needs assessment, devised a communication and awareness strategy plan and prepared a DPR/applied for a loan under R-APDRP Part C accordingly. Also some ITIAs took the initiative (and cost) to carry out training and communication programmes themselves. All of this had a positive impact on the project and as well as allocating time and funding for these activities. It is strongly recommended that time and funds are allocated for business process change management.

Coordination and responsibility have also been identified, as challenges however there have also been extremely successful initiatives, which have taken place to manage these issues, such as the formation of core teams at a central and field level and well-structured project charters. Again both of these initiatives have been recognized as best practices and included in the revised implementation strategy as discussed earlier in the report.

To ensure that all of the work being done now continues to build and strengthen DisCom business in India it is critical that systems are maintained and updated. Whilst the ITIAs now have the obligation to maintain the systems they have implemented for 5 years, there are currently no systems for keeping GIS information (which is the key stone to all asset related processes) up to date. Therefore there needs to be a mechanism in place where every time there is a new connection it triggers a process to initiate GIS mapping and updating of all dependent systems by DisCom personnel. As the majority of DisComs are already struggling with resources it is recommended, at least in the short term, that the R-APDRP scope provide for this either through building capacity within the DisCom or as an outsourced management contract.

All of these activities will require additional capacity in organisations whether in the form of additional manpower or training.

Several recommended positions considered to be critical to the smooth implementation of the most complex activities are detailed in the diagram below. If these positions do not exist already then they should be created. The profile of these positions is also mentioned.

	Central Core Team	Field (Town) Core Team
GIS Head	<ul style="list-style-type: none"> Minimum field experience of 10 years. Power Engineer. Competent IT skill sets. To receive Core training programme for GIS: <ul style="list-style-type: none"> Administration Specification Software/Hardware 	<ul style="list-style-type: none"> Minimum experience of 3 years working in the testing department. Minimum experience of 3 years working in O&M. Power Engineer. Basic IT Skills To Receive full AMR Training
AMR Head	<ul style="list-style-type: none"> Minimum experience of 5 years working in O&M. Experience of planning. Power engineer or Diploma To receive GIS user training. 	<ul style="list-style-type: none"> Minimum experience of 3 years working in O&M. Experience in testing department preferable. Power engineer or Diploma To receive AMR user Training

Project Manager	Technical Manager	Quality Manager
<ul style="list-style-type: none"> Extensive experience in managing and executing large complex projects, with a credible track record. <i>In case if the Project management Head is external to the Utility, the utility should ensure that this person is available through the entire duration of the project.</i> 	<ul style="list-style-type: none"> BS or MS in Electrical Engineering with experience of Electrical Metrology, Utility Practices and Business Model 12+ years managing software, hardware development/delivery teams 10+ years experience in product companies Strong background in system architectures, scalability, and usability Overall strong track record of success in setting technical direction, driving SDLC process Data and Business Analytics Experience with products and services delivery technologies Experience with large scale complex enterprise software applications, networking and network management systems, security technologies, back-office integration and SOA/enterprise service bus - all a plus Knowledge on R-APRDP, Smart Grid 	<ul style="list-style-type: none"> BS in technical field or equivalent with experience of Electrical Metrology, Utility Practices and Business Model 10+ years' experience in quality related fields. This includes several of the following: manufacturing quality, hardware design quality, software design quality, component quality, ISO certifications, Environmental Health and Safety certifications, and standards compliance. Certified Quality Engineer and/or Certified Quality Manager, Experience working with multiple disciplines to design and implement effective and efficient processes Technically savvy, has an extensive amount of hands-on quality implementation experience. Has good people management skills Knowledge of industry best practices. Statistics Electrical Engineering, Metrology, Utility Practices and Business Model System Testing and Validation Experience of Six Sigma

Note: More needs to be done to retain trained/skilled employees within the utilities. Incentives and career development opportunities need to be in place to try to encourage employees to continue their work once the main implementation is completed.

The table below outlines some recommendations on additional training requirements, which could be organised at a central level and funded under Part C of R-APDRP

	Implementation Agency	Management Committee	Central Core Team								Field (Town Teams)				
			Quality Manager	Technical manager	Project Manager	Head GIS	Head IT	Head AMR /Metering	Head SCADA	Head Engineering	Head GIS	Head IT	Head AMR/Metering	Head SCADA	Head Engineering
Communication / Awareness	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓
Business Process Change Management	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓
Project Management.					✓	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓
Basic IT Skills		✓			✓	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓
GIS: administration, specification, software, hardware	✓		✓	✓	✓	✓	✓					✓			
GIS: User Training	✓		✓	✓	✓		✓				✓	✓			
GIS: O&M	✓		✓	✓	✓		✓				✓	✓			
AMR: administration, specification, software, hardware	✓		✓	✓	✓		✓	✓				✓			
AMR User Training	✓		✓	✓	✓		✓					✓	✓		
SCADA: administration, specification, software, hardware	✓		✓	✓	✓				✓	✓		✓			
SCADA User Training	✓		✓	✓	✓					✓	✓			✓	✓
System Architecture: Interoperability, Standards and System Integration Awareness			✓	✓	✓	✓	✓	✓	✓	✓	✓	✓			
ERP Training	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓
Product: specification	✓		✓	✓	✓					✓					✓
Product: Installation Training	✓		✓	✓	✓										✓
Product: O&M Training	✓		✓	✓	✓										✓
Quality & Processes	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓
Utility Induction Training	✓														

The above addresses the most challenging parts of R-APDRP however there should also be consideration for all applications such as CRM, Billing etc but as these applications are often DisCom/State specific then the requirements should be decided during the training needs assesment.

Budget for training and capacity building:

The following extract is taken from a draft approach report submitted by ISGF

Due to privatisation, franchisees, ESCOs etc. there is expected to be at least 100 new players in transmission and distribution the coming few years. If we consider capacity building and human resources for the power sector, a very large quantum of money may be required to shepherd and improve the operations and transition.

If the total budget for training and capacity building is (currently) Rs.150 crore then that equates to just Rs.30 crore/year or Rs.30 lakh/utility/year. Assuming just Rs.5 lakhs per event (which allows only a few outside participants), this would allow only 6 meaningful events/utility/year, which is far too low to meet the business transformation ahead. If the twin needs of R&D and capacity building are considered, modern enterprises spend easily several percent of their revenues on these. Given the size of the power sector in India, even 0.5% allocated for capacity building, (which is extremely low for a fast-growing/public utility domain), translates to approx. Rs1,000 crore/yr. Normally enterprises would fund this themselves however as this is currently not an option substantial Central Government support for capacity building is required.

Proposed Capacity Building (for Smart Grids)

The training and capacity building for all stakeholders should cover the following specific activities:

- Workshops (1 day to several days)
- Seminars (shorter than one day)
- National Events (multi-utility participation)
- International Events (participating only)
- Smart Grid Maturity Model efforts (or equivalent)
- Demos (limited – one-off type)
- On-going demos (these are much smaller than pilots, like a single model flat type)
- Utility-chosen specific training (non-project specific)
- NTPI/CBIP courses
- On-line courses
- Sub-division level training
- Content creation
- Coordination

The budget proposed is that draft report was Rs.663.2 Crore/yr.

Proposed Programme & Estimated Costs

This section is to be covered in detail by the ISGF working group developing the roadmap and cost plan for the 12th plan. However some costs can be attributed to the amendments that we have discussed regarding the revised implementation strategy including a methodology for project monitoring and the additional resources required to carry out these tasks.

Task	Cost/yr.	Units	Total INR
Governance Council	50 crores	1 Team	50 cr.
Communication plan	5 crores	63 DisComs	315 cr.
Cost of core team (New positions etc Superintending Engineer level)	30 lakhs/yr/person Average 5 positions 150/lakh/yr/DisCom	63 DisComs	94.5 cr.
Total Part A			459.5 cr./yr.
Training Part A Related	5 lakhs	6500 Towns	325 cr.
Training Part A SCADA related	5 lakhs	570 Towns	28 cr.
Total Part C			353 cr./yr.
Grand Total			812.5 cr./yr.

Standards, Architecture and Security

The recommendations detailed in this part of the project are as a result of interviews with stakeholders as well as inputs from experts.

The scope includes those smart grid initiatives identified by the ISGF roadmap for advanced distribution in the 12th plan only. The table below provides some indications of the standards to which they should comply and recommendations on further research that could be carried out by the ISGF expert working groups.

	RECOMMENDATION	APPLICABLE STANDARD	ISGF Working Group *
1	Integration within R-APDRP systems <ul style="list-style-type: none"> • Meter Data Acquisition System (MDAS), • Meter Data Management System (MDM) • Geographic Information System (GIS) • Outage Management System (OMS) • Customer Information System (CIS) 	IEC 61968, Common Information Model (CIM), (or Multispeak). Since these standards are evolving, the interfaces should be capable of supporting versioning and backward compatibility.	WG 7 WG 5 WG 4 WG 3
2	Network Planning Tools	IEC 61970, IEC 61968	WG 1 WG 2
3	Integration of R-APDRP systems with ERP systems, in particular Finance and HR	IEC 61968	WG 7
4	Electricity metering – Data exchange for meter reading, tariff and load control	<ul style="list-style-type: none"> • IEC 62056 (DLMS/COSEM for meter communication) • 15959:2011 (and amendments if any) Data Exchange for Electricity Meter Reading, Tariff and Load Control – Companion Specification. 	WG 3 WG 4 WG 7
5	Condition Monitoring, Energy Auditing & Accounting in real time – each consumption point mapped to a meter, a network asset and a bulk supply point. This includes full DT Metering, IP Metering and pre-payment Smart meters for temporary connections.	IEC 61968	WG 3 WG 4

RECOMMENDATION		Applicable Standard	ISGF Working Group *
6	Security	<ul style="list-style-type: none"> • NISTIR 7628 for the Smart Grid Interoperability and Cyber Security • AMI-SEC Task Force – SEC Profiles for Smart Grid System Security – • NERC CIP for Reliability • FIPS140-2 for Computer hardware and software Security and Cryptography • "IEC 62351 series – Power Systems Management and associated information exchange – Data and communication security" is to be included under standards 	WG 10, WG 7, WG 4, WG 3
7	Development of Medium sized (500 KW to 2 MW) and large sized (> 5MW) Micro-grids.	IEC 61950–7–420 IEEE 1547	WG 9
8	Extension of R-APDRP to the smaller towns. 3250 towns expected to be covered under the 12 th Plan.	IEC 61968	WG 2
9	<p>Condition Monitoring and Energy Auditing & Accounting in real time - each consumption point mapped to a meter and a network asset and bulk supply point.</p> <p>This includes full DT Metering , IP Metering and pre-payment Smart meters for temporary connections. 1.5 million DTs (33% of total) proposed in 12th Plan.</p> <p>DT Condition based monitoring and control.</p>	IEC 61968	WG 3 WG 4
10	Network Planning Tools	IEC 61970, IEC 61968	WG 1 WG 2
11	National Power MIS Centre at MoP. Aggregation of Power System Data (operational & asset) at national level for better planning and monitoring	IEC 61968	WG 3 WG 7

	RECOMMENDATION	Applicable Standard	ISGF Working Group *
12	Demand Response for peak load management in all Utilities - target: 5% of peak load	IEC 62054	WG 5
13	AMI for all customers with loads >20 kW (4 million consumers)	IEC 62056	WG 4 WG 5
14	SCADA/DMS for additional Towns: 572	IEC 61968	WG 2
15	Automatic re-closers for faster restoration of power	IEC 61850, IEC 61968	WG 2 WG 3 WG 4
16	Substation Automation and modernization: all 110/132 33 kV and above (GIS where ever feasible; new breakers, numerical relays, bay controllers and transformer monitors). – To be covered under part B of R-APDRP	IEC 61850	WG 2
17	Fiber connectivity for all substations 33kV and above (fiber network connecting 250K Panchayats to be leveraged)	Fiber-optic connectivity standard	WG 3
18	Improvement in HT:LT ratio, Volt-Var Compensation systems and other KPIs	IEC 61850	WG 2
19	Smart or Smart Ready Meters for all new connections	IEC 62051 - 62054	WG 4

Details of India Smart Grid Forum Working Groups:

WG1 Advanced Transmission Systems
 WG2 Advanced Distribution Systems
 WG3 Communications for Smart Grids
 WG4 Metering
 WG5 Consumption and Load Control

WG6 Policy and Regulations
 WG7 Architecture and Design
 WG8 Pilots and Business Models
 WG9 Renewables and Micro-grids
 WG10 Cyber security

Acknowledgements

Project Team (In alphabetical order):

Athawale, Rasika : Independent Consultant
 Bhargava, Anamika: Independent Consultant
 Govindarajan, Sivakumaran : Schneider Electric
 Hartland-Johnson, Bridgit: Energie Dynamique
 Consultants
 Kashyap, Ganesh: Landis & Gyr
 Pillai R: Chairman WG2 Advanced Distribution
 Rana, PH: GUVNL
 Thapliyal, Mitul: Infosys
 Tongia, Rahul: Independent Consultant
 V.Shivakumar: CPRI

Contributors (In alphabetical order):

Alstom Grid
 APDCL
 ASEB
 BESCOM
 Dong Fang Energy
 Feedback ventures
 GE
 HCL Info
 HCL Technologies
 IEEMA
 Infosys Technologies
 JVVNL
 Kalki Communication technologies
 L&T ECC
 L&T Infotech
 LGVCL
 Medhaj
 MERC
 MSEDCL
 MVVNL,
 NDPL
 PFC
 PGVCL
 Reliance Infrastructure Ltd
 Schneider Electric
 Siemens
 TCE
 TCS
 TNEB
 TNERC
 UGVCL
 UPPCL
 WBSSEDCL

Annexure 1: Feedback from ISGF

Comments by Organisation in Alphabetical Order:

Messrs.' CROMPTON GREAVES COMMENTS

1. Considering the current state of Indian DisComs, the R-APDRP specification is over ambitious, and is not achievable in the time frame conceived.
2. Since the core objective of the program is to reduce the AT&C losses to below 15%, the programme should be divided into the following smaller parts:
 - a. Distribution strengthening and SCADA readiness of substations to go in parallel. Automation can be the enabler but cannot reduce the losses to below 15%. It is the improved Distribution network and smart meters with theft indications and improved collection efficiencies, which would lead to the achievement of this core objective.
 - b. Implementation of SCADA – This would involve the verification of data acquisition from all necessary devices, testing of various protocols. At the end of these 2 phases, the backbone for a Distribution Automation System and building block for DMS is in place.
 - c. DMS Functionality 1- Import and update of network model from GIS, synchronizing the network updates, Network Planning, Load Flow Analysis, Volt-Var Control, Loss Minimisation via Feeder Configuration
 - d. DMS Functionality 2 – Load Shedding Application, Fault Management and Service Restoration, Load Balancing via Feeder Reconfiguration, Load Forecast
3. If the programme can be divided into smaller chunks as above with definite deliverables at the end of each chunk (phase) and appropriate identification of metrics to measure the success, we can make meaningful progress.

Messrs.' MICROSOFT COMMENTS

Reference	Comment
General	Based on the utility's maturity, Smart Grid modules such as Meter Data Management, Outage Management Systems, Mobile Workforce Management should be included in the Phase 2 scope, so that investment till date Phase 1 can be recovered faster.
Recommendations for improvements	Flexibility in Specs can result into interpretation, leading to delay and perceived lack of transparency. This could cause accusations among sub-vendors.
Capacity Building	IT adoption DisComs employees should be able to use Technology as an enabler and they should not be overwhelmed with it. Employees should extensively use IT in day-to-day life to fully familiarise and be ready for smart grid adoption. The employees should not get awed by tablets, smart phones, laptops rather they should make it normal way of working and also be enabled to work remotely.
	Unified Communication Employees should be able to leverage unified communication – which integrates voice, email, IM, video, calendaring. This should help reduce travel expenses and reduction in absence due to tours. Once they are able to use technology in day-to-day life, the adoption for Applications such as Workforce Management, Incident Response will be much easier.
	User Interface Applications should have similar user experience across any device whether PC, tab or phone. Homogeneity in application user interface and leveraging applications that the user is already aware of like the browser, spreadsheet, word processing programmes will help the workforce in adapting to newer tools and driving up productivity levels.
	Online/Recorded Training Portal In order to leverage any new tools/applications properly, it is essential that training videos, FAQ's etc. are available to the user. A culture of self-learning can be driven by setting up a central portal with training videos, knowledge base etc. which will help the employees absorb information at their own pace and improve their skillsets.
	Hardware and Software Tools A few states (UP, TN) have announced distribution of laptops/tablets to all students to augment learning. All utility employees should be provided tablets, smart phones or laptops depending upon requirement and level in the DisCom. Accordingly, it should be incorporated in the budget.
Part A GIS (NEW)	GIS should not be a separate package as there will be no one clearly responsible for integration with other applications.

Part A Integrated Operations (NEW)	<p>A combination of events processing engines and integration technologies will be required in order to allow applications to exchange data with each other for operational and reporting purposes.</p> <p>Below is a listing of the various types of integration based on the data, latency, functionality requirements</p>
------------------------------------	--

Type of data	Latency	Integration Type	Functionality
Low Latency Data	Micro-Seconds to Seconds	CEP + OPC Connector	Distributed event processing + analytics, protection and control systems application integration High speed processing, low latency, small packet for alerts
Historical Data	Seconds to Minutes	CEP + Integration middleware like BizTalk Server	Actionable real time monitoring via analytics visualisation Real Time data exposed and combined with Operational Data for trend analysis
Operational & non-operational data	Minutes to Days	Integration middleware + Reporting Engines	Multi-source data aggregation via visualisation & reports Deliver managed BI to improve on-demand, flexible reports and rich analytics
Business Data Repository	Minutes to Months	Business Analytics Engines	Business Case linked KPI's via dashboards & reports spanning operational and real time systems

R-APDRP Part A IT G2 Specifications Pt. 2, 4	<p>Big Data</p> <p>The explosion of data and new data types from devices, sensors has outpaced traditional structured data sources and has led to the evolution of Big Data technologies which are capable of handling structured as well as unstructured data by leveraging low-cost distributed storage and processing. An analytics solution can then analyse both structured and unstructured data sources thus delivering comprehensive operational intelligence. These insights can be made available to business stakeholders using familiar office productivity tools and business value can finally be broadly realised.</p>
R-APDRP Part A IT G2 Specifications Pt. 31 MIS	<p>The SRS should contain a general set of reports to be delivered by the IT applications, but it may not be feasible to fully detail the number and content of reports for each DisCom due to disparate processes and workflows. While the project would cover a significant part of the reporting requirements, the users should be able to use self-service business intelligence capabilities of applications like Excel to generate additional reports.</p>
R-APDRP Part A IT G3 Specifications Pt. 3	<p>Since there may be multiple operating systems involved in the project, the following line should be changed from "on each monitored UNIX/Linux system." to "on each monitored system."</p>

Messrs.' SIEMENS COMMENTS

1. Part A IT Implementation: "Skewed payment terms for IT and SCADA/DMS" or Can be added to Recommendations for improvement for SCADA/DMS
2. Part A SCADA Planning: Do not agree with "specifying the make of the equipment" as it leaves no scope for finding new / competitive vendors.
3. MTS Specification: Section 2 -1.3: Requirement of Historian should depend on the data volume and needs of the utility and should not be standardised for each City/ Utility
4. MTS Specification: Section 2 - 2.1.1 DMS Functions: -

The list of DMS functions and their detailed description seem to be very specific and could be proprietary to some vendors. To encourage competition these function descriptions should not be made so specific and detailed. Different software vendors have different ways to implement these functionalities. Some functions are part of some modules, which are given different names by different vendors. For example the functions of S.no 10, 11,12, 13, 15 are Network Planning functions for which many vendors would give a special module outside the DMS but could be integrated to DMS because of the inherent way in which utility engineers will use these different tools. The description for S. No 9 seems more theoretical and academic especially seeing the actual situation of the Distribution utility networks. Giving such detailed description will not only leads problems in evaluation of bids but also implementation and delays of the projects. I strongly recommend that the detailed description in the clauses as given in points no. 5 to 25 (pages 55 to 61) should not be included in ISGF report.

4. MTS Specification: RTU: Proposal for dual redundant power supply will increase RTU cost. Also, one more separate & additional DC Power Supply will be required which will increase overall APS cost, FMS, Warranty charges. RTU with one PS was found to be OK for distribution utility. Also Utility's PS is has different voltage levels (say 30 VDC, 110 VDC) and there is no standardisation on DC voltage as mentioned in the recommendation.
5. MTS Specification: test Parameters: This recommendation needs to be further checked in detail in view of the different worldwide standards and requirements. This can be further discussed with the technical team.
6. MTS Specification: FRTU: The recommendation given is good provided the FRTU cubicle is housed in utility premises where adequate space is available. However actual situation is that the utility intends to mount these FRTUs out in the streets and crowded areas. By providing these additional items the cubicle will become bulkier and difficult to mount.
7. MTS Specification: FRTU Communications: With the fast changing Communication World a separate communication modem protects the investment of the Utility for not being forced to change the FRTU in case tomorrow it decides to use another communication technology say 4 G or 5G.
8. MTS Specification: FMS: Batteries should be considered as consumables and considered out of the scope of the FMS. Also Communication failure should not be part of uptime calculation for whole system or individual device as GPRS communication has inherent stability issues, which take time to solve.