ADVANCED METERING INFRASTRUCTURE
AMEREN ILLINOIS

I. BACKGROUND

Ameren Corporation has been an industry leader since the advent of automated metering, having been among the first utility companies in the nation to install these devices on a large scale. Today, automated electric and gas meters exist across most of Ameren's 64,000-square-mile service territory. Full-scale automated meter reading (AMR) was introduced across Ameren Missouri's service territory in the 1990's, including Alton and East St. Louis (electric) in Illinois. At the time, the million-meter project was the largest implementation of network meter reading in the U.S. The Alton and East St. Louis service territories in that project are now part of Ameren Illinois.

An aggressive expansion of automated meter reading in Ameren Illinois' service territory began in the spring of 2006 and concluded in early 2010. Now, more than half of Ameren Illinois' gas and electric customers have automated, 1-way, transmit-only meters. This includes 678,000 electric meters and 476,000 gas meters.

During the Ameren Illinois automated meter reading project, an advanced radio frequency (RF) network, capable of 1-way and 2-way communications, was installed by Ameren Illinois' service provider, Landis + Gyr, to interface with these meters. The 2-way communications capability has not been leveraged all the way to the meters since at the time of deployment the meters (endpoints) were 1-way. Meter technology, features, and costs have changed dramatically in the last few years, making 2-way automated metering systems the standard for new "greenfield" deployments in the industry.

Due to early automation, Ameren Illinois' customers have been receiving the benefits of 1-way automated metering, and with it, a large portion of Ameren Illinois' service territory is ready to move to the next level of metering infrastructure and its additional benefits.

Ameren Illinois (AIC), in accordance with the requirements of IL Senate Bill 1652 and IL House Bill 3036, will pursue the next level of metering infrastructure by deploying advanced 2-way metering. Ameren Illinois is required to serve no less than 62% of electric customers with the Advanced Metering Infrastructure (AMI).

On July 5, the Natural Gas Consumer, Safety and Reliability Act (SB 2266) was signed into legislation. As a result, Ameren Illinois will move forward with plans to deploy gas AMI to 56% (468,000) of gas customers in connection with the rollout of the AMI network and AMI electric meters.

Since acquiring the business process design (IBM), systems integration (IBM) and technology (Landis+Gyr/Ecologic) vendors, the AMI team has performed an array of project tasks to prepare for the golden meter deployment in Q2 2014. These task include business process design, implementation of the software design, application development, plus installation of the network and data management technical environments.

The AMI Core team received formal Ameren Board of Directors approval in December 2012 to deploy AMI meters to 62% of electric customers. This document will provide an overview of the Gas AMI component of the AMI program. Also provided will be the the benefits that are expected to be realized by implementing Gas AMI concurrently with electric AMI.

II. PROPOSED PROJECT

To achieve the objective of deploying AMI to 56% of Ameren Illinois gas customers, Ameren Illinois estimates an additional $64M in capital expenditures.

Specific changes and modifications required to achieve the goals of the project will be implemented at different stages during the project. There are two main phases to the overall project implementation as indicated below:

- Phase 1 - Business Process Design (BPD), Integration and Change Management. Within this phase, the team has evaluated RFPs, issued contracts, and began system design and integration efforts. In addition, the team is thoroughly reviewing AIC business processes to ensure seamless integration of AMI and Meter Data Management System (MDMS). This phase is underway and the team is currently completing the final stages of business process design (remote connect/disconnect, Peak Time Rebate (PTR), data analytics, and outage).

- Phase 2 - Meter Deployment and Network Deployment. Within this phase, AIC will deploy meters first in Illinois operating centers that do not currently have AMR followed by areas served by AMR. Phase 2 of the project schedule is on track to deploy meters in Q2 2014.

  To ensure that 56% of Ameren Illinois gas customers are served via AMI by year 2022, Ameren Illinois must install 468,000 two-way gas radio modules. Meter and module deployment is expected to begin in the 2nd quarter of 2014 and conclude in the 4th quarter of 2019.

- In concurrence with the aforementioned phases, the Meter Data Management System (MDMS) and Advanced Metering Infrastructure (AMI) software applications will be installed and integrated with Ameren's current systems based on business process design requirements. Data analytics efforts will also begin to ensure proper reporting, analysis, and project goals are being achieved in accordance with the requirements of the law.

The stages below outline Ameren Illinois' high-level plan for implementation of information technology software applications and equipment to provide for accurate and timely billing, remote connect/disconnect functionality and customer access to usage information.

Functionality Release Schedule

Stage 0	Stage 1	Stage 2	Stage 3
Install foundational meter data management system and AMI system	Process and Bill Residential Simple Rates and customers from RTP (Real Time Pricing) program via legacy interface	Upgrade processes and system to support remote connect/disconnect	Support Peak time rebate pricing and other Time of Use (TOU) programs
Prepare systems and processes for installation of 2-way communication network	Integrate AMI and MDM systems and prepare for billing Transfer AMI interval data to Retail Energy Suppliers	Revenue Protection Analytics	Prepare systems & processing for Commercial and Industrial (C&I) billing
Manage Asset Information	Customer Web Portal Green Button		Event processing such as outage notification and restoration
2nd Quarter 2014	**4th Quarter 2014**	**2nd Quarter 2015**	**4th Quarter 2015**

The Gas AMI infrastructure will deliver the following benefits to gas customers:

- Improved efficiencies and reduced operating costs from automated meter reading without the need for on-site meter readers
- Reduction in estimated bills
- Customer access to energy usage information to improve their energy and cost management
- Reduction in theft/tampering
- Remote interrogation of the gas meter module to determine health, reducing deployment of field resources to the customer's premise

The Gas Metering technology will include the following functionalities:

- Increased information available to the customer
- Remote diagnostics of the gas metering module
- Remote firmware upgradeability within the gas metering module and the AMI network
- Secure data and controls to ensure privacy and prevent unauthorized access

- Interoperable to the extent possible and practical (e.g. common communications protocols).

III. ECONOMICS

Utilizing the AMI network infrastructure for both electric and gas metering will provide additional, incremental benefits to gas customers. If the gas meters are not automated with advanced gas metering technology as electric AMI meters are installed, manual meter reading resources and related infrastructure will need to be retained strictly for reading gas meters. The expected result of retaining manual meter reading resources and related infrastructure strictly for reading gas meters will be an increase in meter reading costs for AIC’s gas operations.

In alignment with formula ratemaking and the gas rider, the total project (Electric and Gas AMI) assumes perfect rate making (no regulatory lag). The total (Electric and Gas AMI) project’s IRR is 6.83% which incorporates the legislatively defined equity return of 580 basis points over annual average 30-year treasury rates for Electric AMI.

IV. RECOMMENDATION

Due to the existing Ameren Board of Director’s approval, passage of gas legislation and a successful review by Ameren’s internal gate approval board process, the project team requests authorization of an additional $64M to implement gas AMI concurrently with electric AMI.

As regulatory recovery for investment in the remaining 38% of electric customers and 44% of gas customers becomes clear, Ameren Illinois will return to the Coporate Project Oversight Group and Ameren Board of Directors for additional approval.

CORPORATE PROJECT OVERSIGHT COMMITTEE

V. SCOPE CHANGE REQUEST RECOMMENDATION & ACTION ITEMS

Gate Approval Board (1, 2, or 3)	Recommendation
Gate 3	Strengthen areas indicated and verify with GAB

Program/Project Action Item	Completion Date	Comment
Complete level 3 schedule	May 1, 2014	Per the AMI schedule management plan, the spring 2014 baseline will incorporate the tier 2 vendor schedule and the remaining systems integration schedules
Complete Detailed design for each stage	In accordance with Level 3 schedule	
Corporate safety review of safety plan from Apex (installation vendor)	CPOC Gate 3	Plan to be reviewed by Carl Spence (AIC) and Corporate safety designee
Identify Information Technology TBD (to be determined) resources	Ongoing	Per the AMI staffing plan, resources needs will continue to be evaluated and added to the project team

VI. STRATEGIC ALIGNMENT

	Alignment
Integrated Resource Plan	N/A (AmerenMissouri)
Segment Business Plan	The AMI program is in alignment with the Ameren Illinois strategic goals to comply with the Energy Infrastructure Modernization Act, Improve the regulatory Gas framework, Improve Customer satisfaction and Employee engagement. The successful implementation of the AMI program will touch all aspects of the aforementioned business goals.
Discretionary or Non-Discretionary	Non-discretionary in accordance with the SB1652 (EIMA)and SB226 (Gas legislation)
Budget Forecast	The $240M Electric AMI capital cost estimate is a component of the overall Modernization Action Plan budget of $643M. Yearly budget reviews (or as needed) of the overall MAP program will be performed to ensure that budgetary and metric obligations are met and evaluated. The Gas AMI capital cost estimate is $64M in addition to the $240M appoved electric capital costs.

VII. PROGRAM/PROJECT BENEFITS

	Benefits
Customers / Ratepayers	Below is a summary of the major quantifiable benefits expected out of the implementation of AMI. **Operational:** Reduction in Meter Reading Costs Reduction in Field & Meter Services Reduction in Unaccounted for Energy Efficiency Improvement in Customer Care IT Costs Savings Improved Distribution System Spend Efficiency Outage Management Efficiency **Customer / Societal (Electric Only):** Reduced Consumption on Inactive Meters Reduced Uncollectible / Bad Debt Expense Demand Response Energy Efficiency Plug-in Electric Vehicles Carbon Emission Reduction Customer Outage Reduction Benefit .
Shareholders	No regulatory lag due to formula ratemaking per SB1652 No regulatory lag due to SB 2266 gas infrastructure investment legislation and future test year rate cases

VIII. COST ESTIMATE (Electric & Gas)

Capital	**($ millions)**
Meters	$168.2
Information Technology (Applications & Operations)	$61.3
Program Management	$17.3
AMI Operations	17.2
AFUDC	$10.0
Program / Project Risk Based Contingency	$30.0
PROGRAM / PROJECT COST ESTIMATE	$304.0

Work Order #(s)	Total Capital Work Order Value ($ millions) (Program / Project Cost Estimate –Direct Costs)
C3632 – Advanced Metering SB 1652 (Includes AMI Meters / Modules & Installation, AMI Commmunications Network, IT Development Costs, Program Management Costs)	$263.2
J00DD – Adv Metering Infrastructure	$4.8
J02CT – AMI System Integration Software	$29.6
J02J0 – AMI Hardware	$4.0
J02QM – AMI Integrated Ops Center	$0.4
J02WB – AMI Field Area Network	$1.6
J02XQ – AMI Test Labs	$0.4
Total	$304.0
Note: Additional work orders will be created as needed for those items included in C3632	

	($ millions)
O&M Expense	$334.3
O&M Benefits	($786.5)
O&M (Net)	($452.2)
Cost Class Estimate 5 (0-2% program/project definition) 4 (1-15% program/project definition) 3 (10-40% program/project definition) 2 (30-70% program/project definition) 1 (50-100% program/project definition)	Estimating Method Stochastic or Judgment Primarily Stochastic Mixed, but Primarily Stochastic Primarily Deterministic Deterministic
Class 2 – Meters/Software Applications **Class 3 – Systems Integration**	Analogous, Expert judgment, vendor estimates, vendor bids, detailed take-offs and completed contracts

IX. ALTERNATIVES CONSIDERED

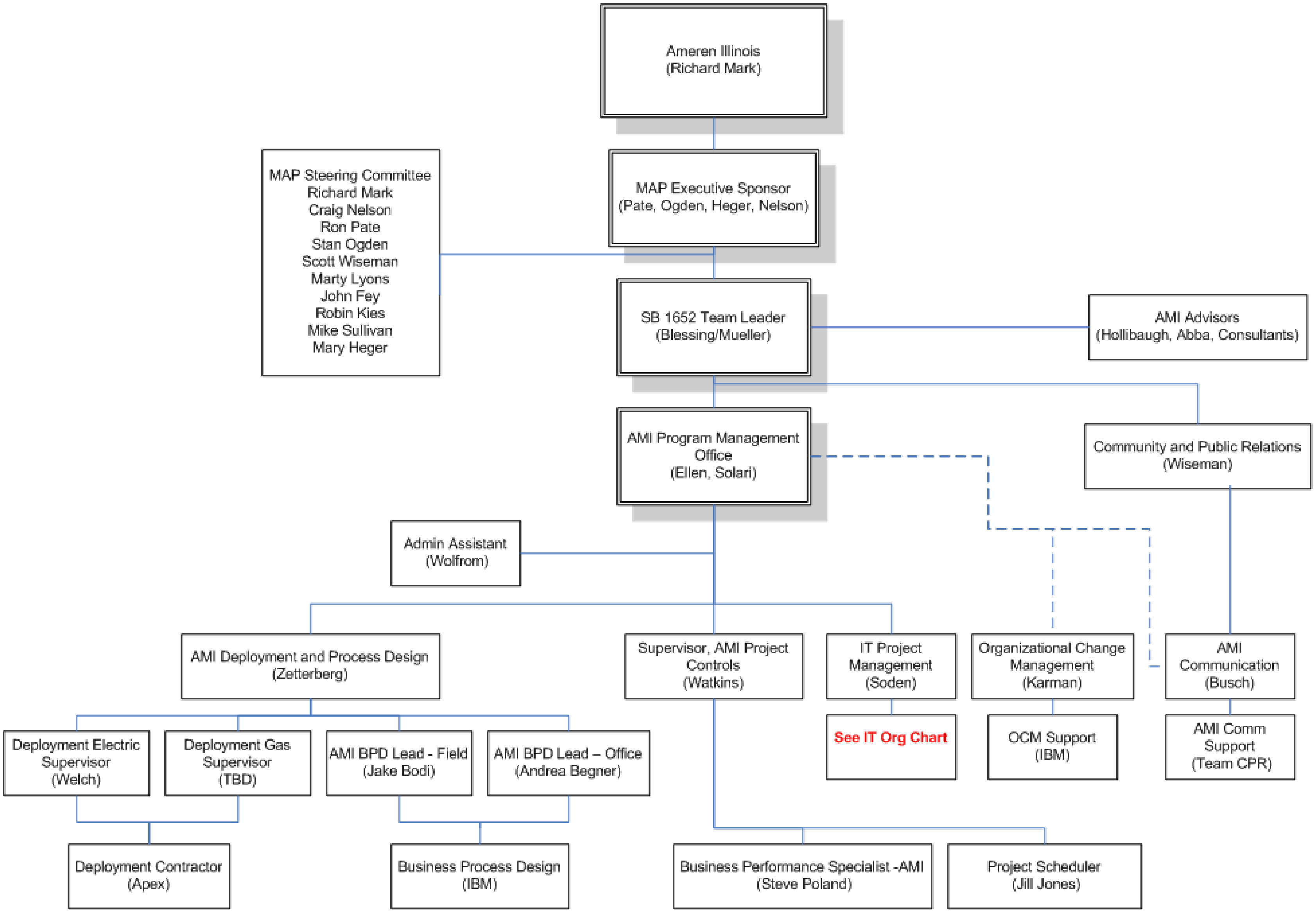
Criteria	Maintain Current State	Option B	Option C
Time Frame	Prevents Ameren Illinois from receiving the benefits of formula ratemaking	Accelerate deployment timeframe – crowds out other MAP investment preventing the achievement of non-AMI MAP metrics.	Decelerate deployment timeframe – prevents the achievement of AMI metrics, causing ROE penalties and delays to customer benefits
Technology	Prevents Ameren Illinois from receiving the benefits of formula ratemaking	Use point-to-multi-point communication technology in lieu of RF mesh. Reduces communication pathways when network elements aren't communicating properly.	Use powerline carrier or cellular-at-the-meter communication technology. Prohibitively expensive for Ameren Illinois' service territory.
Program/Project & Construction Management	Not applicable	Outsource PMO functions to a third party consulting firm. Increases risk of knowledge transfer issues from deployment to operation.	Not applicable
Contract Structure & Commercial Terms	Not applicable	Separate contracts for meters, communication technology, installation. Increases risk of coordination errors and issues.	Not applicable
Cost ($ millions)	Not applicable	Approximately equal	More expensive with no additional functionality or advantage
Risks	Prevents Ameren Illinois from receiving the benefits of formula ratemaking	Increased coordination issues, network functionality, in-house knowledge of system operation, potential to miss metrics required by SB 1652	Increased cost, potential to miss metrics required by SB 1652, delays benefits to customers

X. SCHEDULE

AMI Milestones	Timeframe	Date
Project Begins		**01/02/13**
Business Process Design Begins		**01/02/13**
Stage 0 Command Center Complete	**Stage 0-A**	**09/27/13**
Hillsboro Network Deployment Begins	**Stage 0-A**	**09/30/13**
Preparation for Meter/Module Deployment	**Stage 0-B**	**02/14/14**
Deploying AMI Meters/Modules	**Stage 0-C**	**06/30/14**
Process & Bill from RTP (Real Time Pricing) Program Deployed	Stage 1	10/31/14
MDM & AMI Systems Integrated for billing	Stage 1	10/31/14
Web Portal Implemented	Stage 1	10/31/14
First Deployment Analytics (3% Elec, 3% Gas Complete)		12/30/14
Operational Analytics Complete	Stage 2	03/31/15
Remote Connect / Disconnect Process Upgraded	Stage 2	03/31/15
Peak Time Rebate / Critical Peak Pricing Deployed	Stage 3	10/31/15
C & I (Commercial & Industrial) Billing Systems Prepared	Stage 3	10/31/15
Event Processing Deployed (Notification / Restoration)	Stage 3	10/31/15
Advanced Meters Enabled		12/30/15
Annual Deployment (15% Elec, 12% Gas Complete)		12/30/15
Annual Deployment (27% Elec, 27% Gas Complete)		12/30/16
Annual Deployment (39% Elec, 38% Gas Complete)		12/30/17
Annual Deployment (51% Elec, 48% Gas Complete)		12/30/18
Annual Deployment (62% Elec, 56% Gas Complete)		12/30/19

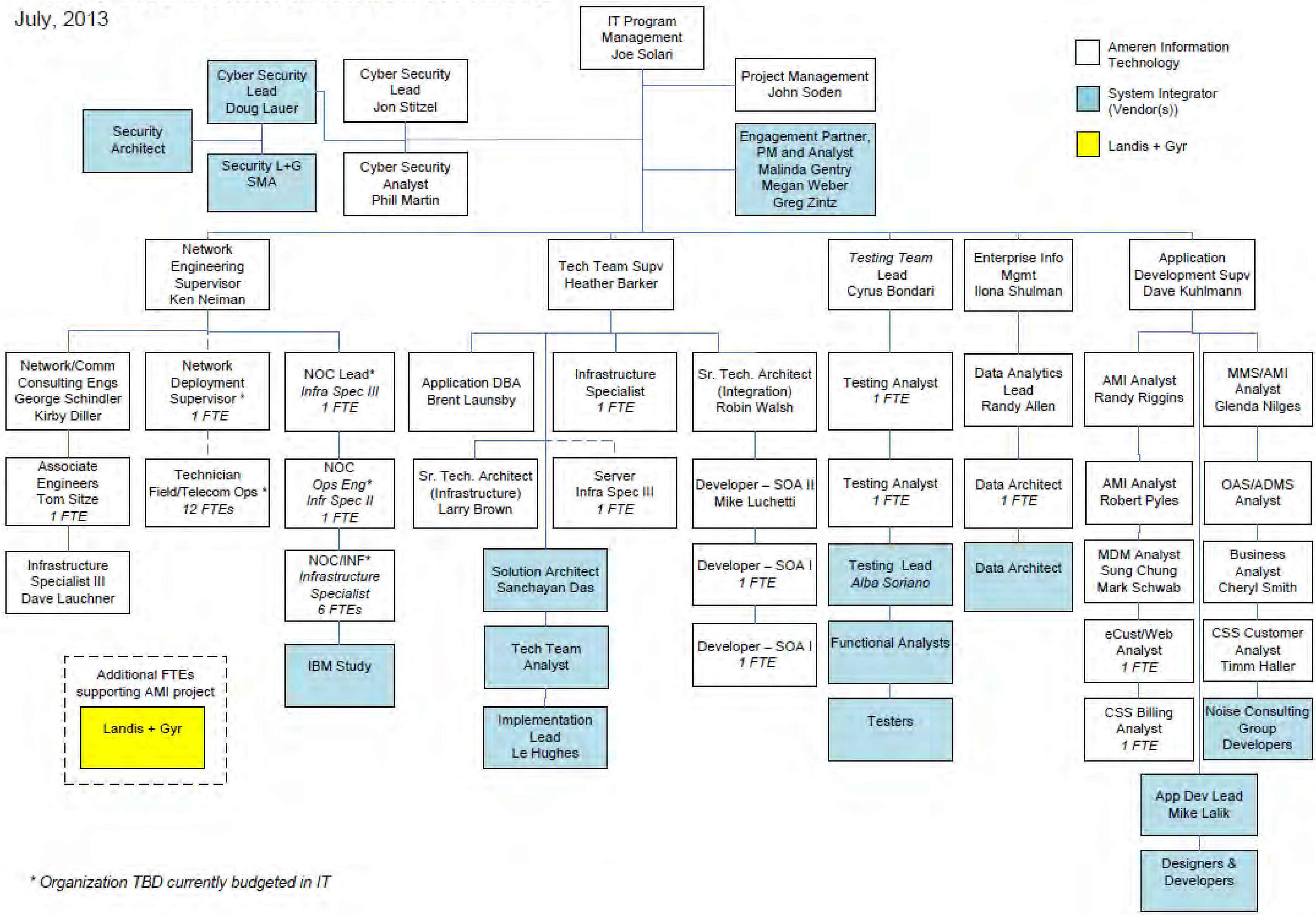
1. Bolded milestones are scheduled in the current Primavera baseline according to our schedule management plan.
2. Annual ICC Submittals in baseline.

XI. PROGRAM/PROJECT TEAM ORGANIZATION



IT Organization Structure AMI and Smart Grid Communication Network

July, 2013



** Organization TBD currently budgeted in IT*

XII. RISK MANAGEMENT PLAN

- Risk Manager and Risk Owners will meet monthly to:
  - Discuss any potential trigger events
  - Review risk response plans
  - Update risk register
- Risk register maintained on the AMI/SGCN SharePoint site and updated monthly during the risk meeting
- Risks will be communicated to project stakeholders monthly as part of the monthly reporting and team meetings
- The total amount of contingency is $30M based on the evaluation of risks in the risk register. The risks listed below are the top five risks detailed in the AMI risk register.

Major Risk	Impact	Mitigation Strategy	Contingency ($ millions)
Unplanned change in Scope / Requirements	Scope / Requirements could change based on the results of the detailed Business Process Review and Design - which could impact overall cost, functionality, or schedule. An approval process will be needed to accept changes in scope.	Rigorous change management process including approval tiers, lead team reviews and schedule/costs analysis will control and document scope additions.	$12.8M
Lack of a defined, documented, and/or communicated smart meter opt out program	Proactively addressing this issue could result in reduced customer negativity surrounding the program, and in-turn, less scrutiny and customer opt-outs. If this option is explored, Ameren will have to work both internally as well as closely with the vendor teams to determine the impact of an opt-out program on the smart grid systems.	Address opt out through the regulatory or legislative process and create an opt out program.	$4.3M
Difficulty or resistance with tying business case operational benefits to the division budgets	AMI operational benefits are not recognized in the corporate budget	*Develop baseline data for current CBA *Develop mechanism to compare and track operational benefits by working with AIC subject matter experts	$3.3M
Ameren and their union will not be able to efficiently structure and approve new job duties, roles, and responsibilities.	Ameren will not be able to restructure and deploy new crew structures (e.g. combination and mixed crews) for planned and unplanned activities which will leverage the available data, automated nature of the equipment,	Ongoing discussions with labor relations and the organizational impact team as part of the planning effort to communicate and prepare for future state processes that will impact union personnel.	$1.9M

Major Risk	Impact	Mitigation Strategy	Contingency ($ millions)
	and new equipment maintenance cycles and duties.		
Lack of program adoption by customer base	Without the expected program adoption by customers Ameren could miss out on planned business case benefits. Strategies to drive customer adoption (including incentives, etc.) will be critical to drive program participation.	Communicate benefit of DR/EE programs to customers Continuous review of stakeholder metrics	$1.2M

XIII. FINANCIAL ANALYSIS

Corporate Model (Excluding Formula Rates Benefit)

$ millions

Year Ending	2012	2013	2014	2015	2016	2017	2018	2019	2020	Cumulative 2021-2042
INVESTMENT SUMMARY										
Capital Expenditure	$3.8	$26.0	$49.8	$70.0	$43.0	$36.3	$35.3	$33.4	$0.2	$6.4
Book Depreciation		($0.8)	($5.8)	($14.3)	($23.8)	($27.1.)	($28.7)	($26.1)	($20.3)	($157.2)
Other										
Net Annual Capital Investment	$3.8	$25.2	$44.0	$55.7	$19.1	$9.2	$6.6	$7.3	($20.1)	($150.8)
Net Cost Basis @ End of Period	$3.8	$29.0	$73.0	$128.7	$147.8	$157.0	$163.6	$170.9	$150.8	$39.0
Net Income Effect		$0.2	$1.5	$3.9	$6.8	$7.7	$7.9	$8.0	$8.4	$48.7
Net Unlevered Free Cash Flow	($3.8)	($25.1)	($42.5)	($50.2)	($7.4)	$6.1	$6.9	$4.6	$33.6	$198.1

Financial Returns	IRR
@ 15 Years from Date of Initial Cash Flow (2012)	4.25%
@ 30 Years from Date of Initial Cash Flow (2012)	6.83%

Assumptions	
1)	Electric Perfect rate making / no regulatory lag / all costs are prudent / full recovery of all O&M and capital expenditures
2)	Gas AMI costs to be recovered through SB2266 gas infrastructure investment legislation and future test year rate cases, no regulatory lag
3)	Deployment to 62% of electric customers and 56% of gas customers within 8 years
4)	Includes $3.8 million of actual costs in 2012