GIS Leading Practices Guidebook

Data Cleanup Methods with Cost-benefit Analysis Guidance

3002010509

GIS Leading Practices Guidebook

Data Cleanup Methods with Cost-benefit Analysis Guidance

3002010509

Technical Update, December 2017

EPRI Project Managers

J. Simmins
J. Roarke

ELECTRIC POWER RESEARCH INSTITUTE
3420 Hillview Avenue, Palo Alto, California 94304-1338 ▪ PO Box 10412, Palo Alto, California 94303-0813 ▪ USA
800.313.3774 ▪ 650.855.2121 ▪ askepri@epri.com ▪ www.epri.com

DISCLAIMER OF WARRANTIES AND LIMITATION OF LIABILITIES

THIS DOCUMENT WAS PREPARED BY THE ORGANIZATION(S) NAMED BELOW AS AN ACCOUNT OF WORK SPONSORED OR COSPONSORED BY THE ELECTRIC POWER RESEARCH INSTITUTE, INC. (EPRI). NEITHER EPRI, ANY MEMBER OF EPRI, ANY COSPONSOR, THE ORGANIZATION(S) BELOW, NOR ANY PERSON ACTING ON BEHALF OF ANY OF THEM:

(A) MAKES ANY WARRANTY OR REPRESENTATION WHATSOEVER, EXPRESS OR IMPLIED, (I) WITH RESPECT TO THE USE OF ANY INFORMATION, APPARATUS, METHOD, PROCESS, OR SIMILAR ITEM DISCLOSED IN THIS DOCUMENT, INCLUDING MERCHANTABILITY AND FITNESS FOR A PARTICULAR PURPOSE, OR (II) THAT SUCH USE DOES NOT INFRINGE ON OR INTERFERE WITH PRIVATELY OWNED RIGHTS, INCLUDING ANY PARTY'S INTELLECTUAL PROPERTY, OR (III) THAT THIS DOCUMENT IS SUITABLE TO ANY PARTICULAR USER'S CIRCUMSTANCE; OR

(B) ASSUMES RESPONSIBILITY FOR ANY DAMAGES OR OTHER LIABILITY WHATSOEVER (INCLUDING ANY CONSEQUENTIAL DAMAGES, EVEN IF EPRI OR ANY EPRI REPRESENTATIVE HAS BEEN ADVISED OF THE POSSIBILITY OF SUCH DAMAGES) RESULTING FROM YOUR SELECTION OR USE OF THIS DOCUMENT OR ANY INFORMATION, APPARATUS, METHOD, PROCESS, OR SIMILAR ITEM DISCLOSED IN THIS DOCUMENT.

REFERENCE HEREIN TO ANY SPECIFIC COMMERCIAL PRODUCT, PROCESS, OR SERVICE BY ITS TRADE NAME, TRADEMARK, MANUFACTURER, OR OTHERWISE, DOES NOT NECESSARILY CONSTITUTE OR IMPLY ITS ENDORSEMENT, RECOMMENDATION, OR FAVORING BY EPRI.

THE ELECTRIC POWER RESEARCH INSTITUTE (EPRI) PREPARED THIS REPORT.

This is an EPRI Technical Update report. A Technical Update report is intended as an informal report of continuing research, a meeting, or a topical study. It is not a final EPRI technical report.

NOTE

For further information about EPRI, call the EPRI Customer Assistance Center at 800.313.3774 or e-mail askepri@epri.com.

Electric Power Research Institute, EPRI, and TOGETHER…SHAPING THE FUTURE OF ELECTRICITY are registered service marks of the Electric Power Research Institute, Inc.

Copyright © 2017 Electric Power Research Institute, Inc. All rights reserved.

ACKNOWLEDGMENTS

The Electric Power Research Institute (EPRI) prepared this report.

Principal Investigators
J. Simmins
J. Roarke

This report describes research sponsored by EPRI.

This publication is a corporate document that should be cited in the literature in the following manner:

GIS Leading Practices Guidebook: Data Cleanup Methods with Cost-benefit Analysis Guidance. EPRI, Palo Alto, CA: 2017. 3002010509.

ABSTRACT

A utility's Geospatial Information System (GIS) is the key data source for all engineering and operations applications. It is the "one source of truth" for asset locational information and one of the key components of deriving a network model for planning, operations, and analysis. Using a series of "GIS Immersions," EPRI hopes to identify common problems with GIS data as well as leading practices to alleviate them.

This paper covers the first two of five GIS immersions at several types of utilities: investor owned, municipal, generation, and transmission. It also reports on a meeting of the EPRI GIS Interest Group at the Fall Power Delivery and Utilization Meeting September 13, 2017 in Denver, Colorado.

Keywords
GIS
Geospatial Information System
Geographic Information System
Cost Benefit Analysis

ELECTRIC POWER RESEARCH INSTITUTE

Deliverable Number: 3002010509

Product Type: Technical Update

Product Title: GIS Leading Practices Guidebook: Data Cleanup Methods with Cost-benefit Analysis Guidance

PRIMARY AUDIENCE: GIS Professionals

SECONDARY AUDIENCE: Engineering and operations professional.

KEY RESEARCH QUESTION

A utility's Geospatial Information System (GIS) is the key data source for all engineering and operations applications. It is the "one source of truth" for asset locational information and one of the key components of deriving a network model for planning, operations, and analysis. Using a series of "GIS Immersions", EPRI hopes to identify common problems with GIS data as well as leading practices to alleviate them.

RESEARCH OVERVIEW

This paper covers the first two of five GIS immersions at several types of utilities: investor owned, municipal, generation and transmission. It also reports on a meeting of the EPRI GIS Interest Group at the Fall Power Delivery and Utilization Meeting September 13, 2017 in Denver, Colorado.

KEY FINDINGS

- Utilities have several common problems with GIS that are independent of the type of utility.
- The common GIS problems include, data quality, data completeness and integrations.
- These common GIS problems originate from a combination of historical data collection methods, difficulty with data hand-offs between business groups and lack of understanding of the criticality of GIS data.

WHY THIS MATTERS

The value of this research will be to find common areas of interest to foster collaborative research.

HOW TO APPLY RESULTS

The reader is encouraged to examine this report and to reach out to EPRI for participation in the GIS research that result from it.

LEARNING AND ENGAGEMENT OPPORTUNITIES

- The reader may be interested in joining the EPRI GIS interest group. The interest group has monthly calls for GIS professionals to hear a presentation, discuss issues, and learn about publicly available EPRI learnings at no cost.
- The information in this report may be of interest to members of the EPRI Distribution Program (P180). Interested parties might want to contact the Open Geospatial Consortium (OGC) for further information on topics of GIS interest.

EPRI CONTACTS: John Simmins, jsimmins@epri.com

PROGRAM: Information and Communication Technology for Distribution (PS161C)

Electric Power Research Institute
3420 Hillview Avenue, Palo Alto, California 94304-1338 • PO Box 10412, Palo Alto, California 94303-0813 USA
800.313.3774 • 650.855.2121 • askepri@epri.com • www.epri.com

© 2017 Electric Power Research Institute (EPRI), Inc. All rights reserved. Electric Power Research Institute, EPRI, and TOGETHER...SHAPING THE FUTURE OF ELECTRICITY are registered service marks of the Electric Power Research Institute, Inc.

CONTENTS

LIST OF FIGURES

1 INTRODUCTION

Using utility immersions, EPRI will be able to identifying, document, and report on leading practices to overcome common data issues. The research report will describe strategies, tactics, methods, and processes to improve data quality. Also, the self-assessment tools utilized by utilities to clean GIS data will be documented. By documenting leading practices and techniques to improve data quality, utilities can improve utility operational efficiencies, asset efficiencies, system operational efficiencies, reliability, safety, and other benefits that may be hard to quantify.

2
UTILITY "A"

System Demographics

1. How many electric meters does your utility serve?
    - Radial - *~137,000 meters*
    - Mesh - *0 meters*
2. Miles of distribution line.
    - Overhead - *667 circuit miles*
    - Underground - *1372 circuit miles*
3. Do you have gas customers? - No
4. How many places is locational data stored?
    - *Officially one, the production GIS database. We have multiple one-off databases for individual projects or needs, but those databases need to hit a certain level of "critical mass" to move into the production GIS database. The only other database like GIS is the PLS-CADD database, which is an engineering database for transmission lines. There a general migration of data from one-off solutions into the GIS. The philosophy for last 10 years is that there are three, main data repositories: GIS, SAP and Sharepoint (SCADA is the fourth can be a fouth) We use SharePoint for drawing management.*
5. How many places is network model data stored?
    - *Excluding the SCADA system, one. We do use SynerGI for load modeling, but the source of that data is the production GIS database that is extracted twice per year.*
6. How many people on GIS staff?
    - *There are 21 staff in the Geospatial Technologies department:*
        - *1 manager*
        - *1 supervisor Operating Records, who supports Operations use of GIS data.*
            - *5 GT Techs*
        - *1 supervisor CAD Services, who support engineering design inputs into GIS*
            - *10 GT Techs*
        - *1 supervisor Analysts, who support GIS application and underlying infrastructure*
            - *2 GT Analysts (1 CAD, 1 GIS)*
            - *1 System Admin*
            - *1 Developer*
7. What does your GIS staff do?
    - *This is included in the company Geospatial Technologies Department Review report.*

Quality Assurance

1. Does your utility have data quality control checks on incoming data?
    - If yes, please describe these.

        - We try to. Our techs and analysts are trained to look for abnormalities in whatever data they are given and to question it. Operating Records field checks 75-80% of all the construction going on, including opening up energized equipment to verify phasing and connectivity. It is a very manual process.
    - How is this working for you?
        - Works pretty well but turnover is a concern. It is rare to find a construction mistake.
2. What are your data quality goals for GIS? (Maintain accuracy to within X%.)
    - We try to maintain over 99% accuracy for connectivity/phasing and high profile equipment like transformers. This is due to the GIS plays in outage management and transformer management.
3. What is your most difficult data quality issue to address?
    - Old legacy data and the lack thereof.
    - What have you tried to address the issue? We have spot projects here and there to populate missing data that has proven needed (such as underground primary cable sizes and the year/drawing/wo that installed them. We have not done a full scale conflation project, though. One example is that they never put wire sizes on drawing for underground. So, they have to go through the engineering work orders and figure it out. Might be part of a conflation project.
4. Is there a process of maintaining and improve asset-related information over time?
    - For how we operate right now, our processes are pretty good. But we will need more information in the future. It is recognized and we are in the early stages of an Enterprise Asset Management project to tie us into the company's Enterprise Resource Planning system (SAP). That should provide a lot more data about the system in a more automated fashion (rather than manual data entry). They do not track asset maker. The GIS group has a supervisor go to the monthly standards meeting.
5. What methods have you employed to true up the GPS locate of assets (especially older assets)?
    - We've done an inventory on our transmission system and distribution poles where we've attempted to capture GPS. It was decently successful, but we still used aerial photography as a guide in some instances. We are installing empty duct throughout our territory to prepare for the end-of-life of 40+ year old cable, which we are surveying in their paths and putting those more exact locations in GIS. The struggle has been exact placement vs. map readability. The functionality is exact locations in CAD, readable map in GIS.
6. Do you have algorithms to catch entry errors or unreasonable values?
    - If yes, please describe these. We recently implemented a GIS-based transformer load management tool that does flag if transformer loading values seem unreasonable or if the data about the meter tied to the trf seems incorrect (such as a 3 phase customer on a single phase trf). Other than that, we do not have automated checks on this. It's pretty much experience driven and manually tracked. Load data comes from the meter reads in SAP. They then average them by day and rebuild it based on the month.

7. Do you have algorithms to maintain the following?
    - Transformer-to-phase connection
        - We have a tool that can check this, but it is rarely run. The Responder Outage Management is highly dependent that this is accurate and it catches data issues in day to day usage. Responder refreshes Cache every 60 minutes.
    - Meter-to-transformer connection
        - We run a monthly process to update this data tie. This is not for Responder but for Transformer Load Management.
        - What system do you do transform load management (TLM) in?
            - They have a tool in GIS that they wrote.
    - Confirm conductor size and length.
        - None
    - Correlate active street lights to accounts with active one in CIS.
        - We have 5 major street light types/customers:
            - City of Lincoln (who owns the majority of the lights and LES maintains them
            - City of Waverly (LES owns and maintains these lights for Waverly)
            - Lancaster County (same as Waverly deal)
            - State of Nebraska (State owns them, LES maintains/provides energy)
            - Security lights (LES owns/maintains, customer "rents")
        - We track the "ownership" of the lights for the government entities and generate the information for Customer Service to create the bill.
        - At this point, we do not track which customers rent the security lights, but that may change.
    - Appropriate fuse size for transformer of connected KVA
        - We just started tracking this for pad mounted transformers because they are in the middle of changing fusing standards. Otherwise, it has been standards based for decades and all the pertinent employees have laminated cards showing the fusing standards.
    - Appropriate equipment KV rating for system installed
        - We track the KV for all equipment installed on the 345kV, 115kV, 35kV, 12kV, and the downtown network. But that only denotes that is the voltage of the system the equipment is installed on. We do not track the actual rated kV the equipment can be used on.
    - Other?
        - We track circuit information automatically down to the meter and try to track the phasing down to the meter (with Schneider Electric's ArcFM Solution software). We are highly successful on circuit tracking and phasing on the primary system (99%) but less successful on the secondary/meters (95%).
        - Meters are updated from SAP in the GIS on a weekly basis. The process is automated with an exceptions tracking process.
8. What is the frequency of as-built to as-operated model updates?
    - The rule for GIS is that "if it's energized in the field that day, it needs to be energized in GIS that same day"…this applies to the primary voltage systems, not services. We feel we are successful over 95% of the time on this due to the operational criticality of

the GIS system. We do official as-builts of the CAD drawings, but that process can take a lot longer.
    - Responder sits on Esri and refreshes the cache every hour. It takes about 5 seconds to refresh.
9. At what granularity do you do as-operated model updates?
    - The primary system is updated daily as described in the previous question. The services are updated within 2-4 weeks of them being installed. Meters are updated weekly.
10. Do you have dedicated resources devoted to cleaning up data?
    - In a sense. Operating Records and the GIS analyst do clean up during down times or for projects.
11. Percentage of staff or staff time devoted to cleaning up data?
    - I estimate typically less than 20% of staff time. We are in an initiative to clean up the GIS database, so it's 50% of the analysts' time at the moment. The primary source of problems is legacy data.
12. Are external data sources used to improve GIS data? If so, how?
    - Aerials may be used to clean up locational data. (I know aerials can be hard to use for this due to state plane shifts, but we utilize a very localized coordinate system developed by Lancaster County/City of Lincoln that reduces variances to less than a cm). We also will utilize data from inspection projects to improve on data quality, but inspections are typically driven by/from GIS.
13. Where do you get external data?
    - Landbase?
        - We get our landbase (streets, ownership parcels, legal lots, addresses, city limits) from the City of Lincoln/Lancaster County. With the exception of preliminary plats or plans, we do not modify this landbase in any way. Any corrections on landbase are forwarded to the city/county. We update this info on a monthly basis.
    - Other?
        - We get environmental, flood plain, and water/sewer system information from the city/county as well. We try to avoid maintaining datasets that belong to other governmental agencies.

Usage

1. What is the main purposes for which GISs are used at your utility:
   - Now?
     - Daily operations. GIS is the considered the active "live" map of how the system is designed to operate. With the Responder Outage Management System running on top of the GIS map, we are also tracking the live state of how the system is "switched" and all planned work involving the distribution system. It is also used heavily as a research tool as we have links to drawings and historical work orders throughout the GIS map (upwards of 25,000 links).
     - GIS is considered a mission critical technology right behind the SCADA system. If it goes down completely, our company is essentially blind on distribution.
     - It has become the main platform for mobile technology at LES, with GIS planning and managing multiple inspection and mobile workflows.
     - Right now, GIS is considered the master asset database for distribution equipment. We handle the entire "cradle-to-grave" process for distribution transformers. The street light and joint use attachment bills are derived from GIS reports. It is the basis for the SynerGI load models.
   - In the future?
     - In the future, we will tie GIS to the SAP ERP system. GIS will still be the master asset repository because we are tracking more granular data than SAP needs. Part of this project is to implement an electronic design package that will capture more granular data at the time it is designed and move it into GIS/SAP. That design package might be CAD or GIS-based.
     - A big goal of this project is to turn on SAP's analytical engine and have it start examining the inspection data for trends. This will allow us to be more proactive instead of reactive in maintenance. SAP's BI Warehouse. This goes to Hanna in 2022.
     - There are still discussions on if GIS' role of being the inspection/maintenance application will continue or if it will be turned over the SAP with a GIS-driven map embedded in it.
   - Do you have the data that is needed for each of those purposes?
     - We are missing a large amount of detailed information about the older assets. But since we are very standards driven, our plan is to just default data to what the standards are and build the data with the actual attributes through daily usage.
2. Describe the amount of asset-related information that is stored in your GIS.
   - Explicitly: Transformers, poles, pedestals, switches, fuses, reclosers, capacitor banks, junctions, pull boxes, approximate meter locations, joint use attachments, switchgears, elbows, secondary/service conductor, primary conductor.
   - Implicitly: cutouts, grounds, arrestors.
   - What we are missing but should track: anchors and guy wires.
3. How do you support GIS data over time (tracking of historic changes, management of future proposed changes)?
   - We have Esri .MDB and .GDB backups monthly going back to 2003. In some cases, we do track to some degree where primary cable has been abandoned and the

historical service territory. We also track the history of the distribution transformers. They are on DVDs in a firebox in stored on-site.
  - For newly designed assets, Operating Records monitors the crew schedule and starts drawing in the assets around the time the crews start work. Otherwise, we put hyperlinks in the map to the pre-construction drawings and color those links differently to stand out as pre-construction.

4. How does your utility handle updating asset information when equipment is swapped out during storm restoration, especially with foreign crews?
   - There are standard forms for tracking the installation/removal of poles and transformers. We do not track when fuses change and we do not track changes in overhead conductor during storms (even though we probably should). Buried cable is not replaced during storms, only repaired or isolated.
   - Foreign crews are always led by an LES employee and that employee is in charge of tracking changes.
5. What types of distributed generation or storage data are stored and the purposes for which it is used
   - We have very little in the way of distributed generation or energy storage in our system and all of it is behind a meter of some sort. We plan on tracking it through the metering point and have it as an attribute of the meter.
6. Where are electrical assets monitored (test results) and tracked throughout their lifetime?
   - That information is a bit scattered.
     - GIS manages the pole testing data as best we can.
     - While GIS runs the Transformer Management system and transformer maintenance tracking, the testing paperwork is still on paper and in a file cabinet.
     - The cable reel database is a standalone Access database.
     - GIS manages the failed equipment database in a standalone GIS database.
     - We just started doing Tan Delta tests on our cables and working through how to store/manage that data.
7. Do you use GIS to manage relay assets – existence, capabilities, physical location, network connection, and settings?
   - We just manage the existence, location, and connectivity. The settings are managed with the SCADA relay settings database at this point.
8. Do you use GIS to manage communications assets – existence, capabilities, physical location, network connection, and settings
   - We own and manages its own fiber optic network for SCADA and IT communications (along with a small amount of leased fiber for government entities). This includes fiber cable information, patch panels, risers, splice cans, connectivity model, and circuit modeling.
9. Do you include service conductors in your GIS model? Yes
   - Conductor type, size and distance? Is distance estimated? We do track size and type, but not distance.
   - If yes, is this an approximate distance or field verified distance? The distance is probable +/- 20 feet.
   - If approximate, how was the distance derived? GIS Line Length.

10. What is the average length of time from the completion of construction to the update in GIS? What is the time to close work orders?
    - Time to close work order can be 30 days to 2 years, depending on the project. But that has more to do with administrative activities than GIS updates. We update GIS independent of the work order closing because it can take them so long. All we do with GIS during the work order close is get whatever info about the assets we didn't have when we drew it in and verify information. GIS' goal is for a work order to spend less than 14 days in the office.

User Accessibility

1. Do you stress locational accuracy of base data or are they optimized for visual presentation in your GIS?
    - Mostly optimized for visual presentation. We try to place poles and fiber optic as locationally accurate as possible and we are just starting to show ducts as locationally accurate.
    - Thjs is an on-going debate in GT. CAD Services draws almost locationally accurate while GIS draws a more "geoschematic". This makes it difficult to share data. But to use the CAD Standard across the boardwould make the GIS maps very difficult to read and interact with.
2. User access to GIS data – Do you use
    - Web pages?
        - Just getting ready to launch our web initiatives.
    - Self-serve options?
        - Somewhat. We use ArcReader and ArcMap to server out maps using pre-defined map displays. We have a few power users who know how to add data or modify the maps, but the majority of our users take what we give them.
    - Queries?
        - The Analyst or Operating Records areas typically do the queries.
    - Outside parties (like for DER)?
        - We use ArcGIS Online for our outage map and another ArcGIS Online template for Street Light Outage Reporting, but that's it for now.
    - Mobile devices?
        - We are mainly using ArcGIS Collector on our mobile apps. Our field laptops are running a full GIS desktop client using a locally copied Esri File Geodatabase.

Integration

1. What systems does the GIS integrate with?
    - Full integration? Only the Responder Outage Management System, but Responder is essentially a GIS add-on. We provide data to SynerGI. We share data with SAP via CSV files.
2. What data is transferred?
    - For Responder and SyngerGI, we share the full network model and equipment attributes.

- For SAP, we receive the customer addresses and phone numbers for Responder and for generating mailing lists.
- We use GIS as a backdrop for some AutoCAD projects, but it is a copy of the GIS production data.

3. How does your utility coordinate asset management systems and GISs?
    - GIS is the distribution, transmission, and fiber optic asset management system
    - What data is stored where?
        - All the connectivity data and information needed to operate the grid. We have some "engineering" type data in there, but GIS was designed around system operations.
    - How it is synchronized?
        - Manual data entry for the most part.
    - How do work and crew management systems use asset data from both/either system?
        - Engineers and designers use GIS as a starting point for design, but the design itself is done in CAD.
        - We have no crew management system. The field crews do have GIS available to them on their laptops, but the troubleshooters and cable locators are the main field users.
4. Do you use the Common Information Model (CIM) at all?
    - No
5. % of CIM compliant variable names?
    - Unknown.
6. Does your system include all the asset information for all pole and pad-mounted installation and can be linked back to a job estimating system? For example, could you order all equipment and hardware to replace a pole and all its hardware from the information contained within GIS?
    - Directly? No. You would have to make a few or a lot of assumptions to build a Bill of Materials, depending on the equipment.
    - With the future electronic design package, we are discussing adding the compatible units spec numbers to the equipment so this could be done.

Miscellaneous

1. What questions do you have from other utilities?
    - How are other utilities handling the locationally accurate vs map readability issue without redrawing everything?
2. G & T focus
    - What (if anything) is shared with distributors?
        - LES is vertically integrated (generation to the meter). We have a couple of PPAs with two other cities, but nothing major and they request no data.
        - Since the City of Lincoln owns the street lights, they sometimes request data about it that we provide in geodatabases.
        - We also do a lot of work with other utilities and consultants as LES is considered the "lead utility" in all construction projects. We will give them information about

the location and types of facilities we have in an area to avoid construction conflicts and damages.

- GIS as a shared service – any concept of this?
  - Would need to know what you mean as a "shared service".

Summary

The biggest change in the next five years is the enterprise asset project in SAP. Somewhere in accounting, they have some sort of asset management. They do FIFO on assets. They are overstated on the asset books. Objective to true up the asset list. Trying to get SAP to leverage their asset management. They want to get a design product, like designer (Schneider). May convert a couple of techs to analysists. Get the field crew to do data entry. Big problem is the different difference between CAD standards and GIS standards and the level of detail.

3

UTILITY “B”

System Demographics

1. How many electric meters do you serve?
    a. Radial – 2.4M electric customers, total
    b. Mesh – intra Atlanta, 9,200 customers
2. Miles of distribution line.
    c. Overhead – pole line miles = 65,000 includes primary and secondary counted separately
    d. Underground – trench miles = 20,000
3. Do you have gas customers? Yes, but there is zero interaction with them and no plans, no one has said it was could to combine. They cannot overlay now but could since they are all Esri. They will look at it for groups that need it. Merger is only 1 year ago.
4. Other op-cos – they have a common damage assessment to assist in mutual aid. They can’t just click a button and look. It takes a special request. Looking at web services but have no driver. Very little Southern company level data needs. Have a little more access to transmission. Have merged trans and dist into “Power Delivery”. Transmission GIS at Forest Park, GA. They still use a relational database for assets but GIS is only for maps. Distribution is much more sophisticated. Looking at combining T&D because of new Esri capability to model different voltates “from generator to meter”. Patchwork of companies in GA with no visibility into these small utilities. Can’t see a reason for visibility into these small utilities. GAPO doesn’t share info with other companies. They compete for large companies. They compete on reliability and cost. Look up 1974 territorial act. A load has to be 900kW connected to be able to compete. The EMC has to build a line to connect them. They don’t just get a bill from whomever they want to buy from. It’s a one time deal – if they pick you they are stuck with you. They have “customer choice” corridor where multiple companies compete due to proximitiy but there is no joint ownership at distr. level. There is joint ownerhip at the transmission level. There is some spatial inaccuracy from the customers that were added via topographic analysis in 1974. If someone is in GA power but closer to an EMC, all three parties agree.
5. How many places is locational data stored? Depends on the asset. The GIS is global keeper (tranformers, wires, etc.) some asset management system look at poles and will have history. Don’t have enterprise asset management. Customer accounting data system has customer to transformer data. Asset inspection database for transformer maintenance. OMS is fed from GIS. Bulk feed nightly. If accounting is done, it takes 48 hours to get a new service into GIS, one extra day to get to OMS. The nightly bulk feed is by feeder “dirty feeder”. Oracle OMS. Track “off nominal condition” but after 90 days, you bet on the naughty list and the change get set back or sent to GIS to make it permanent. They track double dead ends and tie lines. Jumpers and cutouts are tracked in OMS and they will notify GIS if to be replaced with switch.

6. How many places is network model data stored? Planning uses GIS on request by feeder. XML file to Cyme. GIS is a 3 phase model. Cyme is single phase.
7. How many people on GIS staff? 80
8. What does your GIS staff do? Three groups. 10 people are analysts doing technical support. (business unit IT) End user support, data analytics. Development is liasing with IT. Business unit testing and roll-out. 25 in central GIS (mostly full-time) with 12 contractors. They do bulk editing, interface with Customer service, still produce a set of paper products (bulk printing). Data clean up and database maintenance. 45 or so in regional offices assisting designer with getting the data into the system, do specialized maps, QA/QC because it flows through them. They do not allow engineers to post. It has to go through GIS. They are the drafter for the construction packet. (called GIS technicians). GAPO has 44 regional offices.

Quality Assurance

1. Does your utility have data quality control checks on incoming data?

   If yes, please describe these. At least somebody else looks at it. They are mostly human performed They use designer and designer experess as well as ArcFM. Paper designs go through ArcFM and are self-QC. They do reactive QC. They have turned off the Esri validation for performance. Have not written and validation tools due to performance. Visually validate map connectivity, tells you if it is not energized. Have required fields. The have an unknown option. 90% is legacy from CAD in 2008. CAD had feeder, size, etc. but that’s it. Most fields are null.
2. What are your data quality goals for GIS? (Maintain accuracy to within X%.) Spatial accuracy: as close as can. Have a conflation problem. Network model has feedback loop but no metrics. Don’t physically measure it. They have an RFI out for a conflation vendor.
3. What is your most difficult data quality issue to address? Phasing. Field will move stuff and not communicate back. Mapping is secondary. Use of GIS data as an asset has not sunk in to field staff.
   a. Conflation – doesn’t hurt operationally.
   b. What have you tried to address the issue? RFI out on conflation (talking with one, specific vendor) looking to come in and investigate.
4. Is there a process of maintaining and improve asset-related information over time? Just purchased some data mining software to write validation code. G-ready from Ramtech. OMS re-builds connectivity model. Looking for multiple vertices, cutbacks to clean up.
5. What methods have you employed to true up the GPS locate of assets (especially older assets)?
6. Do you have algorithms to catch entry errors or unreasonable values?
   a. If yes, please describe these.
7. Do you have algorithms to maintain the following? **NO**
   a. Transformer-to-phase connection yes
   b. Meter-to-transformer connection in GIS in database but not geographic, don’t map meter. They use non-version enterprise table to keep it. The table talks to the CIS. Once per week, they done load and GIS tries to autolink. Following weekend, GIS pushes back into CIS. Potential to map down to the meter.

c. Confirm conductor size and length – in versioned portion. Probably the most suspect because there wasn't much of it in the CAD. Secondaries are half not there, the rest are visual estimates. Secondaries are very suspect. Primaries are somewhat suspect. Many are guesses from conversion process.
d. Correlate active street lights to accounts with active one in CIS – have regulated and unregulated, some are maintained. The only people who care are the street-light group. LEDs make it more complicated.
e. Appropriate fuse size for transformer of connected KVA They are trying to mitigate this by combining attributes that could be mutually exclusive.
f. Appropriate equipment KV rating for system installed
g. Other?

8. What is the frequency of as-built to as-operated model updates? Nightly
9. At what granularity do you do as-operated model updates? Dirty feeders.
10. Do you have dedicated resources devoted to cleaning up data? When they have an assignment, they go full time. They don't have permanent, full-time people. Been doing a land-base scrub for over a year and a half. Maybe 4 on any given week.
11. Percentage of staff or staff time devoted to cleaning up data?
    a. The consume and output CAD (Verizon and DOT)
12. Are external data sources used to improve GIS data? If so, how? They do purchase TomTom to do geocoding and do base map. Purchase Core Logic for landbase (parcel usesage) it provides link to customers.
13. Where do you get external data?
    a. Landbase?
    b. Other?

Usage

1. What is the main purposes for which GISs are used at your utility:
    a. Now? Mapping, planning, oms, asset management
    b. In the future? Asset management – how do other utilities do it.
    c. They have looked at Maximo, have some Maximo data. Storerooms use Maximo to track assets. They do not deal much with corporate tax. During annexations, they tried to count poles inside polygons, but more complicated analysis was not possible.
2. Do you have the data that is needed for each of those purposes? Mostly
3. Describe the amount of asset-related information that is stored in your GIS. Poles: height, class, what it is made of, ownership, what is main use. They track attachees (third parties). They are faily diligent on third party. They track every 5 years. 20% of the state every year. They are in their 5th cycle of this. They are just doing validation (doing a ride by). Transformers: KVA, phase, high and low side voltage. No framing hardware except arresters. Try to track construction (123horizontal, or 132 vertical, etc.) They do map down guys. They use a feature, might change to attribute. Nobody cares. Nameplate, no seriel, model, manufacture data. Been asked to track installation date. They have poles creation date (when it was created in GIS). Don't have installation date but could be close enough. Don't track to work order. Too many sources: Designer, Designer Express, ArcGIS, CAD makes it too difficult to get this data into the GIS. Tried to get all engineers to use designer. Engineers too

burdened to draw job with full data to benefit other departments. They overcomplicated workflow. It was taking them hours to do simple jobs. They lost them. San Diego Gas and Electric had same problem. They use CUs (10,000) using their home ground tracking software. Need CU rationalization. Jetts – job tracking and estimating system. JETTs is WMIS. JETTs is Southern company, so all opcos use it and it would be a monster to replace.

4. How do you support GIS data over time (tracking of historic changes, management of future proposed changes)? Historical: system is as built, as nominal. They do track changes over time. Anything posted goes through queue, it tracks change, delete, add, and it is stored in non-versioned tables. Developed by SSP called "All Edits". They keep one year. It is a rolling edit history. They can re-build from it. If something gets deleted, they can go back one year and re-build it. They have used it a couple of time. They could maintain further but don't. They can't look at a point in time of the network. Proposed: Originally (it is a huge problem) switching orders cannot be written until they see it in the model in a proposed (unenergized) state. Design live in sandbox, living its own in own world living in reconcile and post. They will post it for real even if it is not in the field. It will cause some bad predictions. They will call oms team and tell them to put in temporary devices to show as unenergized in the operational model.
5. How does your utility handle updating asset information when equipment is swapped out during storm restoration, especially with foreign crews? Two fold. Esda Arcos software to mark up changes. Work a fair amount of storms are worked on paper. Storm damage assessment on paper. Changes are Esda or paper and put in the next couple of days. 90% goes back like for like, therefore very few changes. Most edits take place in the regional offices. Generally manual.
6. What types of distributed generation or storage data are stored and the purposes for which it is used. Not enough to track in GIS. They track anything they have a contract on. Nothing past the meter. With contract they track type of inverter, size of generation, . Being asked to map behind the meter into the solar farm. There are some utility assets in solar farms that are utility. They have an unregulated branch that does upkeep behind the meter for solar farms. Haven't done that yet.
7. Where are electrical assets monitored (test results) and tracked throughout their lifetime? Most is track in an application called Remedy. They were tracking SF6 in an attribute but no longer. Alternate settings are not.
8. Do you use GIS to manage relay assets – existence, capabilities, physical location, network connection, and settings? Substation group tracks. They map it but do not track it. Just keep enough for OMS, like bus voltage.
9. Do you use GIS to manage communications assets – existence, capabilities, physical location, network connection, and settings They track joint use assets outside GIS. Track cameras. Fiber is not in GIS. Probably in corporate communications.
10. Do you include service conductors in your GIS model?
    a. Conductor type, size and distance? Is distance estimated? All of that. Distance is estimated. Linked attribute that can have a true distance. Primary is better but secondary is visually estimated.
    b. If yes, is this an approximate distance or field verified distance? If approximate, how was the distance derived?

11. What is the average length of time from the completion of construction to the update in GIS? What is the time to close work orders? Within 60 days is policy. Average is 10 business days.

User Accessibility

1. Do you stress locational accuracy of base data or are they optimized for visual presentation in your GIS? The data you are starting off with is already incorrect. They are told to draw their job based on the current condition. If it's currently 100ft off, draw it that way. Make it look right, not be right.
2. User access to GIS data – Do you use
    a. Web pages? Yes, have internal map delivery tool. It aggregates from several data sources. Example, can get aeriel pictures of transmission
    b. Self-serve options? They do mostly custom mapping and reporting. Could be automated. Looking to do more of that. They have FME server. Some Python. Solar group has their own web app they maintain.
    c. Queries? Has a menu of pre-canned queries: jobs more than 30 days old, transformers with no customers, etc.
    d. Outside parties (like for DER)? No
    e. Mobile devices? Mobile mapping, runs disconnected. Laptops. Web based connected via phones.

Integration

1. What systems does the GIS integrate with?
    a. Inputs
        i. CSS – customer meter to transformer
        ii. Designer to JETTs – not used much
        iii. Comercial landbase, parcel layer, transmission asset data
        iv. Imagery data (satellite)
        v. Weather data/radar stream
        vi. Anything else is ad hoc
    b. Outputs:
        i. OMS is the big one
        ii. Cyme planning tool, next biggest
        iii. Can output to WMIS
        iv. Output to three mobile clients for mobile mapping
            1. Gosync
            2. GIS mobile
        v. Pole data – veriset, just deals with poles
        vi. CSS – push back once per week.
        vii. Archive edit tracker
2. What data is transferred?
3. How does your utility coordinate asset management systems and GISs?
    a. What data is stored where?
    b. How it is synchronized? No
    c. How do work and crew management systems use asset data from both/either system?
        i. Event viewer is a vendor built tool for mesh network.

   ii. Tightly integrated to GIS.
   iii. Ancillary documentation that is hyperlinked to folders elsewhere
4. Do you use the Common Information Model (CIM) at all?
5. % of CIM compliant variable names?
6. Does your system include all the asset information for all pole and pad-mounted installation and can be linked back to a job estimating system? For example, could you order all equipment and hardware to replace a pole and all its hardware from the information contained within GIS?
   a. For most equipment they carry enough attribution to find it in a warehouse.

Miscellaneous

1. What questions do you have from other utilities?
   - How is everyone else doing proposed network model updates?
   - Who is doing what with those tools? Who is using engineers to draw?
   - How many utilities are trending to a paperless workflows? Construction diagrams especially. Construction packet. They are in a file cabinet for the next couple of years. Still have maps on the wall.
2. What research would you like us to do?
   - Performance metrics
3. G & T focus
   - What (if anything) is shared with distributors?
   - GIS as a shared service – any concept of this?

4
THE VALUE OF UTILITY GIS DATA ACCURACY

Introduction

This section addresses the economic question, “Are activities to increase the accuracy of GIS data more valuable than their cost?” Naturally the answer is dependent on several variables, including the current state of accuracy and the cost and effectiveness of the particular activities, so the question has no general answer other than “It depends.” This section will discuss and characterize some important dependent factors, and will describe the challenges of using economic calculations to direct activities in this area.

The Economic Framework: Perspective

The question of value in the electric utility industry invites the question of whose value is being analyzed. In the regulated utility business the value to the customer is paramount, specifically whether customers see lower cost over the long run, or whether quality of service (including reliability) is improved enough to be worth any net increase in cost. As is typical in utility-planning analysis, the utility is assumed to fully recover cost in any case. This is fully in keeping with the Integrated Grid Benefit-Cost Analysis Framework published in 2015, as described in an appendix.

The importance of GIS is thought to be rising because of the advance of solar photovoltaics (PV) and other types of DER appearing on many distribution systems. The customer cost for PV continues to fall, and PV penetrations are growing steadily in some parts of the country. Since PV cost is expected to continue falling in real terms for many years, penetrations may continue to rise in more areas of the country, eventually requiring advanced monitoring and control systems to manage voltages and flows, and to ensure safety for employees and the public during and following events. There is no bright line that identifies when an advanced control system such as DERMS (Distributed Energy Resource Management System) is necessary, but utilities in California are already installing DERMS in response to rising PV penetrations.[1]

The value of accurate data

This section examines the value question as a matter of logic, applying general economic reasoning to the question of value by looking at the extremes and conjecturing what happens between the extremes. This may be thought-provoking while providing no specifics, which, as noted, depend on many factors. Nevertheless, it suggests a way to think about the value of accurate data over a range of possibilities.

If a GIS database is not accurate, then mistakes happen; the more bad data, the greater the likelihood that bad data will result in a mistake that loses time and increases cost, and possibly causes or extends an interruption of power to customers. However, data errors are not equal in

---

[1] “California utilities finding their way on renewables integration,” Utility Dive, October 16, 2917. http://www.utilitydive.com/news/california-utilities-finding-their-way-on-renewables-integration/507299/

impact. Not knowing the nature or the frequency of impacts of data errors, the value of reducing them can only be roughly imagined. This contrasts with a quantity like line losses, which occur constantly with a known mathematical relationship to current flow that can be measured or modeled. Even service interruptions occur with enough frequency to be characterized statistically, so that the impact of a new recloser on a line can be reasonably estimated per event or on average. But a bad data entry—say, an incorrect pole location or a phase association for a transformer—may have no impact for a long time, and when noticed it may cause little more than a sigh of recognition. On the other hand, it could cause a serious loss of time when it leads to incorrect decisions by the utility. Herein lies one of the difficulties of placing value on data accuracy: the random and perhaps infrequent nature of the impact of data inaccuracy. This conceptual analysis sacrifices these complicating issues to the interest of the thought experiment.

The extremes are relatively simple. If the database is rife with a high percentage of errors, then the database is worthless. The systems that rely on it are worthless and consequently aren't used. At the other extreme, if the data is perfect, 0% error, all the systems that use the data are perfectly informed (as far as the selection and granularity of data items allow) and work properly (as well as their designs allow). The systems are used and useful, and workers have complete confidence in them.

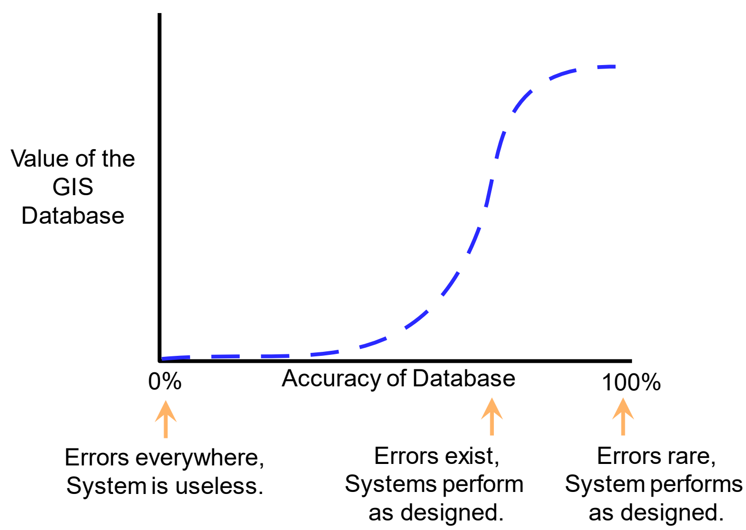


Figure 4-1
Hypothetical Curve of GIS Database Value as a Function of Data Accuracy. For discussion purposes only.

The interesting territory is between the extremes; an s-shaped curve seems reasonable. The overall value of the GIS database as a function of data accuracy might appear as in Figure 4-1, representing a database useless at 0% accuracy with its full value realized at 100% accuracy, whatever it may be. The value of the database is zero for low accuracy, up to some level where it begins to have some value. At some critical value the value rises, though in reality neither the critical value nor the slope is known. The value of the database then levels off as it approaches 100% accuracy. Errors are rare or tolerable. Logic might suggest that accuracy issues that would cause frequent problems would be the first to be corrected since they become known, so that the issues that remain are those with less frequent use or lower importance.

Considering the error cost in marginal terms, we can conjecture a hypothetical curve like the one in Figure 4-2. The shape of a real curve of this type is not known—this one is simply stylized—but it may be useful for discussion purposes. Again consider the extremes: If the database has no valid data then it is useless. The marginal cost of errors is low below the threshold where the system becomes marginally useful; this is a point likely well above 0% accuracy, and corresponds roughly to the critical accuracy level where the system becomes marginally useful, and where increasing the accuracy makes it more useful.

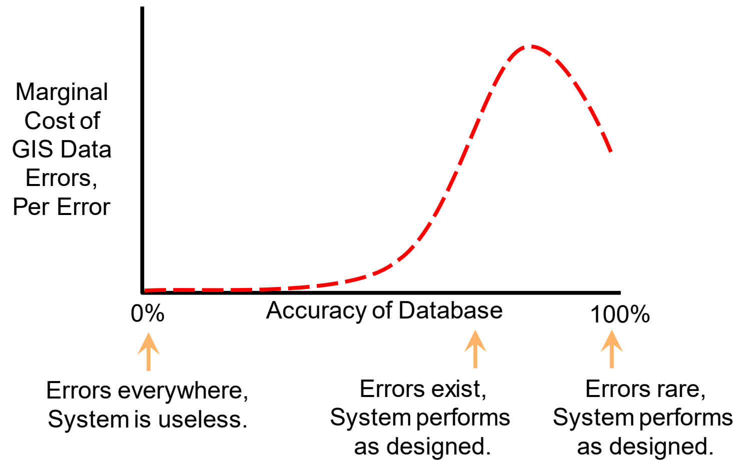


Figure 4-2
Hypothetical Curve of Cost of GIS Data Errors, per Error. For discussion purposes only.

A useful database has errors sufficiently small or rare that users have guarded confidence that they can rely on the information it provides. Errors have cost, but the cost of the errors does not overcome the usefulness of the database or the system itself. Higher levels of accuracy improve confidence and usefulness of the system, but the marginal cost of errors may level off or fall, especially if the errors have been chased into dark corners of the database that are rarely used, speaking figuratively.

Resorting to logic again, we might expect that the cost of finding and correcting data errors depends on the state of data accuracy, as depicted hypothetically in Figure 4-3. If the data are 50% accurate or worse, for example, there are errors everywhere. They are easy to find, but the cost of correcting errors is somewhat like the cost of initial wholesale data collection; it may as well be redone from scratch, noting that correct data are no more readily identifiable than bad data; it may be challenging to discern which existing data items are accurate. As accuracy increases, the incremental cost of general data improvement climbs as the data errors become more sparse and hard to find. Further, frequency of actual use of bad data may be low, which may help to explain why they have lain undetected in the database. Near the extreme where the database is highly accurate, data errors are rare and the cost to find the bad data is possibly quite high per data error. If the utility doesn't know where the bad data is and has no automated means to find it, it can be expensive to hunt it down.

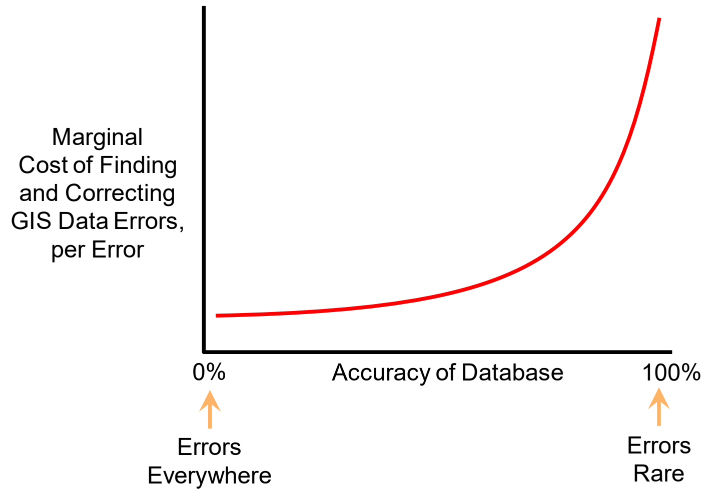


Figure 4-3
Hypothetical Curve of Marginal Cost of Finding and Correcting Database Errors. For discussion purposes only.

Bringing these concepts together, the net marginal value of finding and correcting GIS data errors might appear as the stylized curve in Figure 4-4. At very low accuracy, where there may as well be a total data refresh, the initial net value is negative because the initial steps likely do not render the database useful. Beyond the hypothetical threshold of usability, the value added by increasing accuracy hopefully overcomes the cost of increasing it, assuming that the system with high accuracy does have net value. In these middle levels of accuracy, the system is being used, but errors are encountered in use and may cause costly errors by workers in the field. However, logic further suggests the possibility of a point of diminishing returns, where errors are rare and surprising. Rare errors can still result in costly mistakes in the field, but such incidents are rare; in general workers have confidence in the system. As noted above, the cost of finding the rare errors can be high, and the impact of correcting the rare unnoticed errors may be low, so that the marginal cost of hunting down the rare errors may be greater than the marginal value.

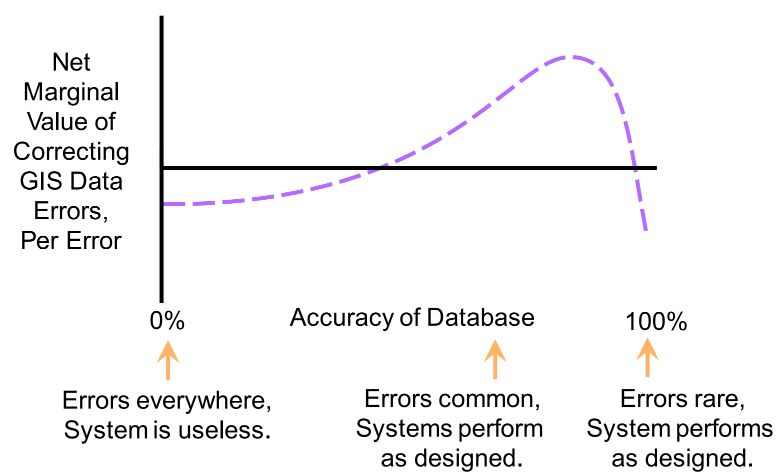


Figure 4-4
Hypothetical Curve of Net Marginal Value of Finding and Correcting Database Errors. For discussion purposes only.

In summary, this thought experiment suggests that some tolerable level of errors may be optimal, but that level is not known. In fact, the accuracy level for a database is not known with any precision unless the bad data points are identified as such. Nevertheless, logic suggests that whether it is valuable for the utility to improve database accuracy is a function of how accurate the database is, and this may be best characterized in terms of how often data errors are encountered in practice and how costly they tend to be. Of course, in a utility GIS the accuracy could be different for different geographic areas or different feeders, so these relationships between accuracy and marginal value may be thought of in terms of the portion of the database specific to these areas rather than to the entire database. That is, a particular substation area might be poorly represented while other areas are in great shape. The use of the system in that area may be specific to the accuracy for that area, and all of the above discussion could apply to the database for that area. Indeed, the distribution systems for different substation areas are electrically independent of other substation areas, and in this sense their GIS representation in the database could be considered as an independent sub-unit of the database.

Finally, it would be a mistake to think of a GIS database in static terms; these databases are being constantly updated as the system evolves to accommodate new devices and greater territory. Without maintenance to minimize new errors, a database's accuracy and usefulness would deteriorate.

Concluding Observations

Subjective, qualitative analysis such as this thought experiment is suggestive but not prescriptive. Ideally an optimal zone of accuracy would be maintained by a combination of conscientious updating to incorporate new information and correction of data errors as they are encountered. However, the utility may not know whether it is in its optimal zone for any particular GIS sub-area, whether for a network or for non-networked substation areas. If the systems that use the GIS are useless in a sub-area because of poor data, then a concentrated effort to upgrade its database may be warranted and economical. The same may be true if the system is used and useful in spite of nuisance data errors. Where data errors are sufficiently rare, the database may be in a zone of optimality, where it can be maintained through conscientious incorporation of new data and changes, including the correction of errors as they are encountered.

Practical Considerations

A thought experiment provides some perspective, but perhaps little practical advice. What should a utility actually do? First, the utility should have a standard procedure that maintains the existing data in view of system changes and new data that constantly arrive. If the utility is going to depend on the systems that depend on GIS data, then this much is required. But maintenance is part of the cost of operating the system; it is not really the question that is dealt with in the thought experiment. That question was moving the database from one state of accuracy to another: however, accurate the database is at present, what is the value of a project to improve it? The thought experiment suggests that this question depends on the current state of accuracy, so the current state of accuracy is an important characteristic to estimate.

Consequently, a utility should understand its GIS data-accuracy position by distribution area (substation area for radial feeders or network area for networks or flexible radial systems). It may be possible to estimate the accuracy of the data by sampling and verifying, but it may be more practical to assess how frequently data errors are encountered and whether they typically cause problems such as increased crew time to get a job done, increased truck rolls, or longer outages than might otherwise be necessary. The field crews are in the best position to know how accurate they feel the data are and what problems could be avoided with better data.

If data errors are cited as a problem by field crews in any of the various distribution areas, then a project to improve the data can be conceived and specified for that specific area. The cost of the project and its likelihood of success can be weighed against the cost of the problems cited. Most of the impacts of the project will be in the “utility operations” domain, affecting operating and maintenance expenses for some period of time. Again, the utility departments that encounter and deal with the problems are in the best position to specify and perhaps quantify these impacts. Coupled with a tight database-maintenance protocol, the improvements in performance should be durable. Improvements in reliability are also possible, and these can be monetized if the reliability impacts can be estimated with any dependability. Some analysis might support an estimate such as a small percentage of the service restoration jobs being reduced in duration by a certain amount of time, such as a typical time to get the right materials for a job that was misunderstood because of inaccuracy in the GIS. However, it is important to relate these delays only to GIS inaccuracy, and not to other unavoidable uncertainties.

5
GIS INTEREST GROUP FACE TO FACE MEETING SEPTEMBER 13, 2017

On September 13, 2017 after the Power Delivery and Utilization Sector meeting in Denver, Colorado, the EPRI GIS interest group met in a face to face workshop. The participants in the workshop were challenged by two questions:

1. With what aspect of GIS data and practice are you most proud?
2. With what aspect of GIS data and practice are you challenged?

Salt River Project (Steven Lopez)

Most Proud:

The circuit models of Salt River Project (SRP) are maintained in real time. The mapping group takes the plans and pre-posts them so when the crew has installed the new assets, the dispatch can immediately turn them on. The document team makes sure it is mapped correctly. Pre-posting is a key element of timely updates. SRP has multiple database models. GE Smallworld that contains impedances and ArcGIS database consisting mostly of the mapping items.

Most Challenged:

SRP would like to learn how other utilities are cleaning their data. Does the ease of data cleaning vary between GIS vendors?

Xcel Energy (Pete Gomez)

Most Proud:

Field teams are equipped with mobile devices with interactive maps. Items such as feedin permits, orders, design sketches are in the database and accessible through the map.

Automatic map correction in the field which sends auto email and have metrics in place to make sure it's taken care of in 24hrs.

Xcel implemented SAP recently. They developed integration between Small World and SAP. The records are kept in both and they synchronize constantly. The SAP interface has a single storage space for records.

Most Challenged:

They want to know how other utilities use Schneider Electric GIS tools. Smallworld for distribution, small world for transmission. Substations Esri. They want to marry for model and system planning

Tri-State Generation & Transmission - (John Hansen)

Most Proud:

Tri-State provides lightning strikes in real time which goes directly to operations and field GIS, how to utilize it acquire it crews to inspect for damage.

They perform inspections and other processes through mobile GIS and all the field teams have tablets.

They have implemented heat maps and look system wide to see if there are certain feeders creating more issues than others.

They interact with their distribution coops to varying degrees, depending on the coop. Some of the coops do not have GIS. The barriers to doing more with their member coops has more to do with funding than it does with technology. They are also challenged to find workers with the required expertise.

Most Challenged:

Currently, they are populating the GIS with Computer Aided Design (CAD) data. The CAD department is separate from the GIS group. The data currently in their version of PLS-CAD needing to be added to GIS. They are looking for a mobile solution to make field changes dynamic in the GIS since there's a conflict between the CAD and GIS departments. Also, there are issues between the CAD and GIS group about the data. They disagree on who owns the data. Should be in a PLS catalog but isn't. This impacts any attempts with data validation. Trying to improve the work flow so the systems are in real enough time.

There is little information sharing between the coop and their member coops. A lot of data is re-created. Everyone is concerned with data issues.

Arizona Public Service (Kathy Grove)

Most Proud:

1. Transmission and uses lidar to map all lines and towers which are GPS accurate. Better than distributions mapping.
2. Have an ArcGIS app for fire mitigation, put together this year which includes all transmission and distributions. App has wind, weather and comm towers information that maps all fires.
3. Conflation interested in who is doing a project and how do they do it maybe chunks and pieces making it more affordable.
4. Wants to find an easier way to integrate CAD and GIS together. John says FME which translates the data using xml.
5. Both transmission and distribution in GIS distribution has been taking the focus. System for a connected network on the transmission side. What would it take to bring transmission up to the point where you can get into EMS for a connected network.

Ameren (Steve Linenfelser)

Most Challenged:

They need a spatial realigning project (conflation). They have multiple spatial repositories that are not put together. Their environmental, transmission etc. are all in separate places. This makes looking at dependencies or the impact of weather or fires more difficult.

They need a rip and replace project for GTech (GTech is Integraph's (Hexagon's) GIS product. It's actually called G/Technology) system to try and bring these things together. Plans are to implement Esri but with the existing, geometric model.

American Electric Power (Greg Hicks)

Most Proud:

The transmission system mapped in GIS. Also, they have location of sensitive span such as anything that goes over buildings or roads. They use live stick ohm meter that will guage health of conductor sleeves. Anchor rod inspections by recreation trail.

They have created an outage viewer that can map where the outages were in the past and see where the problems are for lightning and remediation work.

Most Challenged:

They want feedback how other utilities manage their GIS system as a whole. They are currently implementing portal and are challenged to receive the maximum benefit.

They would like to know more about asset hierarchy in replacing work management software. What's the best practice for asset management and data hierarchy in the GIS system?

Bonneville Power Authority (Douglas Wittren)

In 2014 Bonneville Power Authority (BPA) implemented ArcGIS online and created a public facing gallery page.

The summer of 2015 was a bad fire season where BPA participated in emergency operations with lines to see where the fires were in respect to the lines. BPA was asked to make an application that tracked where the fires were moving with respect to their lines. They were asked to do this in the morning and by 1pm there was a public facing application was available. They used the geoMAC government fire management service for the fire information.

Getting GIS in front of everyone in the agency, put out internal web application called eGIS that was deployed in 2009. It was based on the Geocortex viewer for Silverlight. The application has weather, earthquake, weather in a viewer only environment. BPA gets a lot of feedback on all of that which helps keep the data up to date.

Most Challenged:

Data ownership battle addressed by using metadata. They wanted to expand on record data and process owner etc. in each layer in the database. They exported out all data layers from SDE then looked at what they wanted to track.

Data integrity is important are concerned how they know if the data is valid. Had to find a way to map the validation process. Finally they brought the data back into database and tie by feature class and export reports. Calibri has a app that can suck in data models from various systems and make all the relationships for you. Who's the owner, steward, which systems does this layer belong in.

They think it would be of value if EPRI bird dogged their EMS implementation and publish the findings.

BPA has challenges with access roads getting people where they have to go. They have an old CAD system where they planned on roads to get to their assets, road may or may not be there. Giving people clear direction on how to get there. They just built a new map based of engineering design. Half grid is covered, good accurate GPS road system now. They have some land rights associated with it and although it's not great spatially and doesn't always connect where google maps ends. It is a huge issue until they can integrate for navigation.

Black Hills Energy – SourceGas (John – called in)

Most Proud:

SourceGas is a Black Hills Corporation subsidiary (as is Black Hills Energy). SourceGas implemented a mobile solution to obtain as-built information for new distribution pipe. Field techs would GPS the pipes and describe them to be uploaded immediately.

SourceGas also implemented a mobile tool for right-of-way to be able to look at contracts in the field.

Most Challenged:

SourceGas finds the design tool in SmallWorld more to their liking and is concerned about integrating the two GIS "worlds."

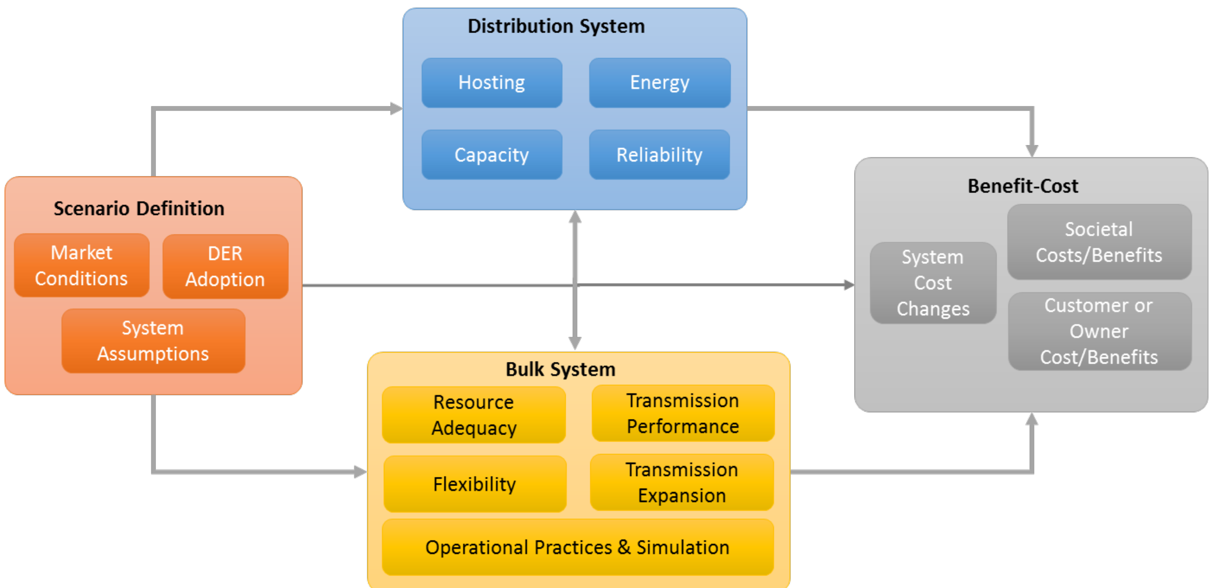
6 RESEARCH OPPORTUNITIES

Below is a summary of the research opportunities brought up through the course of this project and what EPRI proposes.

- Creating a forum where utility GIS people can talk to other utility people without a lot of red tape.
    - EPRI has had a GIS interest group that meets monthly for several years.
    - EPRI will add everyone involved in the workshop to the invite list.
- Getting substation info into GIS.
    - EPRI will reach out to GIS vendors for recommendations.
- Take a look at sharing of data and doing it in a way where everyone wins.
    - EPRI will investigate this in 2018.
- Data clean-up and validation issues – the participants expressed a need for more techniques to obtain and maintain good GIS data.
    - EPRI will investigate this in 2018 in the Distribution GIS/Grid Data Model supplemental project..
- Duplication of data – the team decided they wanted EPRI to look into where and why utilities have multiple sources of data.
    - EPRI will investigate this in 2018.
- The participants wanted EPRI to look into the sharing issues b/w G&T's and coops. It would be beneficial to look at it and see these are the advantages of doing this and monetarily advantageous.
    - EPRI will investigate this in 2018.
- Best practices and integrating metadata.
    - EPRI will investigate this in 2018.
- Drones good at capturing data, what do you do with it and how do you use it without a lot of manual manipulation. Looking at ways to integrate it in a timely manner. Best practices on how to store and retrieve video.
    - EPRI will investigate this in 2018.

A
EPRI'S INTEGRATED GRID BENEFIT-COST ANALYSIS FRAMEWORK

EPRI's Integrated Grid (IG) Benefit-Cost Analysis (BCA)Framework is the successor to its Smart Grid BCA methodology. While the smart grid methodology was oriented toward demonstrations of smart grid devices and systems, the IG BCA framework concentrates on seeking complete solutions to technical issues raised by proliferation of distributed energy resources, intelligent devices, and systems supporting expansive choices for utility customers present and future. The IG initiative seeks answers to a number of research questions that can be addressed through model-based evaluations.



EPRI's smart grid cost/benefit analysis methodology2 was developed jointly with the United States Department of Energy (DOE) in 2010. Subsequently, a guidebook3 aided in setting up smart grid demonstrations, including cost/benefit analysis. Following the smart grid initiative,4 EPRI recognized the need for an end-to-end benefit-cost analysis methodology to aid in optimizing utilities' responses and actions when integrating new distributed resources and

[2] "Methodological Approach for Estimating Costs and Benefits for Smart Grid Demonstration Projects," 2010. (ID 1020342).

[3] "Guidebook for Cost/Benefit Analysis of Smart Grid Demonstration Projects, Revision 3," 2015. (ID 3002006694)

[4] A listing of demonstration documents and case studies can be found at http://smartgrid.epri.com/Demo.aspx.

supporting customer choices. EPRI released an IG concept paper5 followed by a full enunciation of the benefit-cost methodology.6

The original framework was oriented toward problems of integrating distributed energy resources on distribution networks, integrating analysis of the bulk system and the distribution system in a single framework. EPRI continues to develop specific BCA frameworks applicable to various types of current-day utility questions, such as data analytics, communications platforms, or microgrids. These frameworks are developed with topical vocabularies and approaches to problems not contemplated in the original IG framework, but they are consistent with the parent framework in all respects.

The IG framework integrates information and phenomena from both the distribution systems and the bulk system, although this integration is not explicit in every evaluation. Rather, a particular analysis may involve only distribution or bulk, or it may employ a detailed analysis in one domain and an abbreviated one in the other. The framework is comprehensive, potentially including all material information from the technical analyses and combines it with other impacts such as changes in service level and emissions. It can address a wide variety of economic questions and points of view; neither the economic questions nor the point of view are pre-configured.

The new frameworks address new economic questions, but the focus on customers and society is the same. The terms "financial analysis" and "economic analysis" may at times seem interchangeable. However, these are distinctly different for the purposes of the EPRI CBA discussion. Economic analysis asks whether a project will make society's economic pie larger. Financial analysis, on the other hand, is concerned mainly with the investors' slice of the economic pie. Regulated-utility planning analysis is different from both, but it has more in common with broad economic analysis than with financial analysis. EPRI's frameworks are entirely within the economic sphere, concentrating at times on utility customers, and at other times on a broader societal perspective.

Utilities have obligations to provide service within certain standards of performance. When fulfilling non-discretionary obligations, "do nothing" is not an alternative, and cost minimization logic is sufficient. Utility-planning analysis becomes cost/benefit analysis when approaching investments that are discretionary, for example, investments in technology that improve service beyond that considered customary and acceptable. In these evaluations, the cost to customers of an investment or activity is balanced against the value to customers or society of the improvement in service, be it reliability, information, or expanded choice.

Benefit-cost frameworks are employed for a variety analyses in the electricity sector, providing results are both appropriately complete and comparable. A cost/benefit analysis framework may specify a list of impacts or effects that will be examined when evaluating a prospective alternative courses of action. Implicit in this is that these impacts will be monetized (to the extent practical) so that a clear balance of costs and benefits can be determined. It is also implicit that double-counting of either costs or benefits will be avoided. None of these frameworks is

[5] *The Integrated Grid: Realizing the Full Value of Central and Distributed Energy Resources*, EPRI. Palo Alto, CA. 2014. 3002002733.

[6] *The Integrated Grid: A Benefit-Cost Framework*, Palo Alto, CA. 2015. 3002004878.

intended to prevent the analyst from including anything that is material to the result; for completeness they may rather specify phenomena or cost and benefit changes that are immaterial in any particular case.

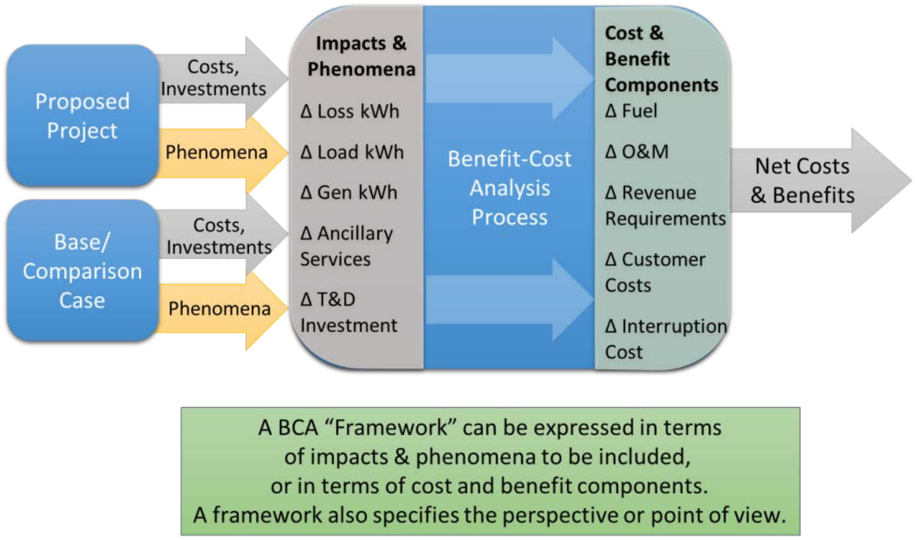


Figure A-1
Benefit Cost Analysis Framework

An important characteristic of a framework is the perspective, or point of view, of the economic analysis. That is, whose costs and whose benefits are to be counted? Will it be customers of a utility? Will it be society at large? These are among the first questions that an analyst should ask when a project is being formulated, because it can have implications for how the physical analysis is done.

Aside from the included phenomena and the analytical perspective, there are some methods common to most economic BCA. For example, a decision analysis examines cost changes between at least two alternatives with different physical circumstances. Adopting one alternative over the other results in physical changes, or impacts. Changes in utility assets and/or expenses may result. Some costs are avoided, while others incurred. Market interactions (price, power flows) may be affected.

In some cases customers are impacted directly, affecting quality of service. Customers may also affect the system with their DER. Finally, there are societal impacts, or impacts that are normally externalized. Customers within the purview of a BCA might experience a small portion of these impacts, such as changes in emissions, but the impacts of emissions may spread much farther geographically than just the customers of a utility.

Relevant to utility-planning analysis is the structure of utility costs and the nature of customer and societal impacts. It is common in utility-planning analysis to assume that the utility recovers its cost fully under all alternatives evaluated. Utility cost includes all expenses, including taxes, and return of and on investment. Assuming the utility is "whole" under all scenarios is intended to lessen or eliminate utility financial concerns from a decision that is focused on customers' costs. This is consistent with the "regulatory compact" concept that the utility is provided with full cost recovery in return for least-cost decision-making.

Utility costs can be categorized into domains, as shown in Figure A-2. First we consider the cost of the utility itself, that is, the people of the utility and the tools they use to get the job done. Next is the operating costs of the physical power system, including fuel and other operating expenses. Generating efficiency and power system losses affect this cost component. The third domain of cost is investment- or asset-related costs, which include return of and on investment and any taxes. Taxes are mostly income and property-related, and since income is related to investment (in U.S.-style regulation), all of these taxes are included in this asset-related category. Naturally, the power system itself is composed of assets, and the utility's people make them run, but these asset related costs are accounted for separately from operations. All together, these three domains of utility cost we refer to as the utility-cost function. The periodic revenues a utility requires to recover all expenses and asset-related costs are called revenue requirements. The utility-cost function can be thought of as the set of accounting rules and methods that produce a utility's revenue requirements for a project or for the entire utility.

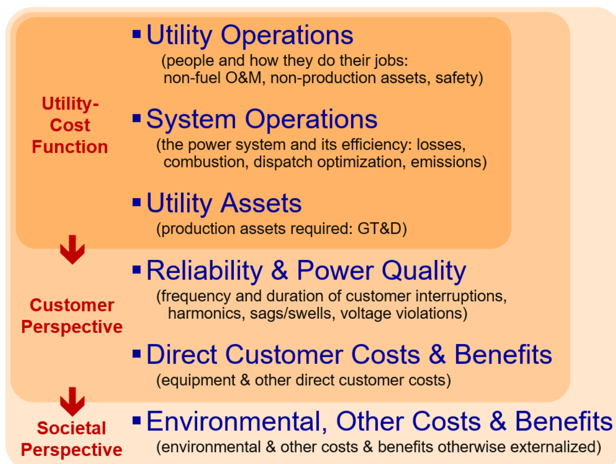


Figure A-2
Definition of Domains of Costs and Benefits and their Contributions to Customer and Societal Perspectives

Changes within the utility will cause changes in the various components that make up revenue requirements; usually a planning analysis will deal explicitly with only these changes rather than with the total cost of the utility. Figure A-2 shows some of these changes in costs that combine to determine a change in revenue requirements related to a project. The figure also indicates that for some utilities there are changes in cost coming through the utility to/from the surrounding market. After all, many utilities are distribution companies only, and only some of those distribution companies actually buy and resell energy to customers. The intent here is to generalize as much as possible while recognizing these variations in utility structure.

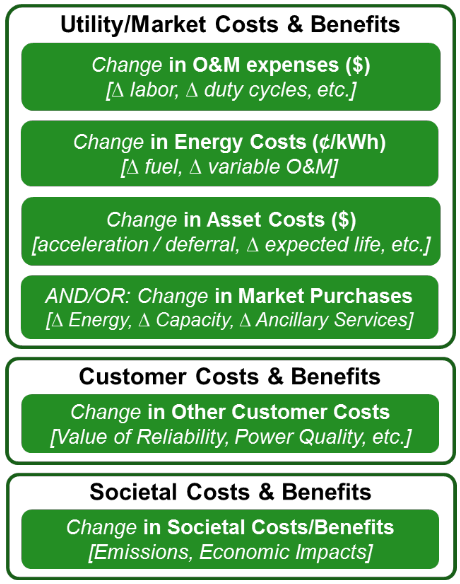


Figure A-3
Cost and Benefit Components within each Domain

Referring back to Figure A-2, the second domain is the customer domain, where we aggregate the impacts and costs that affect the customers directly. Reliability and power quality affect the customer, implying either increased or decreased cost accordingly. Service interruptions are widely recognized as costs for customers, and tools are available for estimating these costs.[7] Less amenable to generalization is the cost of power quality problems, where only certain devices or systems fail or suffer increased losses. In any case, these costs are borne by customers directly, not by the utility, but they are important to estimate for benefit-cost analysis. If customer costs of interruptions are not counted, for instance, then there would appear to be no reason to make investments that can improve reliability. Some projects may involve devices or programs that the customer may pay for directly, and these costs can be included as well.

Finally there are the costs and benefits that are normally externalized because they affect a wider population than just the population of customers. To the extent these changes can be estimated and monetized, they can be included to establish a societal cost or benefit from a project.

Note that the customer domain in Figure A-1 is labeled "Customer Perspective," consisting of changes in utility cost added to changes in customer costs. The customer perspective plus the societal costs provides a societal perspective. The societal perspective is not typically used in utility-planning analysis, which is usually limited to a customer perspective. The IG framework can be applied either way.

Types of Economic Analysis Used in Utility Planning Decisions

Utility planners have long done economic analysis that was not characterized as benefit-cost analysis at the time. However, utility-planning analysis is entirely consistent with BCA except for a few limitations. A popular term today is the "business case," but this term seems to have no

---

[7] Interruption Cost Estimator (ICE), available with documentation online at icecalculator.com.

precise definition. For the purposes of further discussion of analysis types, this section categorizes several types of economic analysis used in planning decisions, and differentiates economic analysis from financial analysis.

For the purposes of further discussion of analysis types, this section categorizes several types of economic analysis used in planning decisions, and differentiates economic analysis from financial analysis. Finally, strategic analysis will be described as a planning activity that may make use of these economic techniques. The definitions provided here should help thinking through the kind of analysis needed for various kinds of decisions.

The definitions supplied here for different types of analysis are not official in any way, and the usage of these terms varies across the industry. They are briefly defined here to avoid confusion, followed by a short discussion of each.

- Business case: An umbrella term referring to the reasoning behind or justification for a particular project or task that supports the business at hand. A business case is not necessarily a formal document and has no widely accepted financial or economic criteria. It can be verbal and informal, or it can be a document with detailed analysis. As a loosely defined term, it could refer to any of the following separate types of analysis.
- Economic/Benefit-cost analysis: An umbrella term for that includes broad economic analyses of decisions, evaluating costs and benefits from a perspective of a segment of the population or society at large. Can be used for public decisions or policy analysis.
- Financial analysis: Analysis of cash flows from a project or decision, perhaps with attention to shareholder returns, financing alternatives, liquidity, etc. This analytical form is used for decision-making in competitive unregulated businesses, but can be used in utility financial planning as well.
- Utility-planning analysis: Analysis of utility decisions in a customer-perspective revenue-requirement framework that may also include changes in customer costs or benefits that do not flow through the utility-cost function. Occurring in centralized planning departments, criteria may be public or defined by regulators.
- Strategic analysis: Analysis of possible future states to imagine what is likely, what is possible, what is unlikely, and how the future states may affect the organization. Some economic analysis and organizational analysis may inform strategic decisions and initiatives that follow.

Business Case

A business case provides the reasoning behind a project or task, but this is a general term that says little about the form that the analysis may take. A business case can be informal, even simply verbal, or it can be a fully formed numerical analysis of any kind. Because it is not specific, the term provides no information for describing the requirements of analysis for any particular kind of activity or decision. Though convenient in common usage, the term is not applicable or useful in a discussion of different analysis types and techniques.

Economic/Benefit-cost Analysis

Benefit-cost analysis is a broad term that encompasses various kinds of analyses. It can refer to broad societal economic analyses of the type used to evaluate policy at the highest levels of government, or it can be applied to smaller decisions such as investments in public facilities.

Variations of benefit-cost analysis is common in the electric utility industry, though perhaps under slightly different terms. In utility planning contexts, benefit-cost analysis might refer to planning studies that seek to balance customer or societal costs and benefits with associated changes in utility cost resulting from an associated utility action or investment. The distinction that makes it a benefit-cost analysis and not a planning study is inclusion of customer or societal costs and/or benefits do not flow through the utility's cost function. Examples of external costs are the customer cost of interruptions and the social cost of carbon emissions.

Financial Analysis

Financial analysis in the utility industry is the province of financial planners, distinct from system planners who plan additions and modifications to the physical power system. Financial planners are concerned with planning of financings, debt rollovers, and cash flow issues as the utility acquires or constructs the assets it uses to provide service to customers. Financial planners may also be concerned with cost-recovery issues and the timing of rate increases relative to investments and changes in revenue. While these are all important for a utility to do, they are not within the scope of the typical planning analysis that determines what investments the utility will make as it fulfills its obligation to serve. The methods used in system planning proceed without concern for these financial issues. For instance, system planning assumes full cost recovery, including return of capital and a return on prudently incurred equity capital, commensurate with its risk. Financial implications of system planning decisions are considered by financial planners before funds are committed to a major project.

Investment decisions in competitive unregulated firms are analyzed with various forms of financial analysis intended to determine whether revenues or cost reductions from a project enhance shareholder or owner returns sufficiently commensurate with the risk. This form of analysis is not consistent with decision-making in a regulated-monopoly environment where the firm is obligated to provide a service to the public at minimum cost.

Utility-Planning Analysis for Discretionary and Non-discretionary Projects

Utility-planning analysis is a special case of economic analysis. It adopts a customer perspective, and usually externalizes social costs and/or benefits that accrue to society as a whole.[8] From this perspective, decisions are cast in terms of how they impact the revenue required from customers, as well as how customers may receive (or incur) additional benefits (or costs) that do not flow through the utility-cost function[9] as revenue requirements. Consistent with the regulatory compact, the methodology seeks the alternative that imposes the lowest present-worth cost on

---

[8] Customers may experience some cost or benefit from items externalized, but customers generally experience only a fraction of the total impact of externalized costs. For example, carbon emissions may have long-term global impacts but minimal local impacts within the planning timeframe.

[9] The utility-cost function is the set of accounting and tax rules that determine revenue requirements, that is, the revenue required in each period to recover cost and provide a return on prudently invested equity capital.

customers, under the assumption that, across all alternatives, the utility recovers from customers all costs, including return of and on prudent equity investment.[10]

Non-discretionary Projects (Cost minimization)

Many utility projects are not discretionary to the utility; they are undertaken pursuant to the utility's obligation to serve. In these cases there is no valid do-nothing alternative; the utility must do something. For such non-discretionary projects, the utility determines which alternative minimizes customer cost (revenue requirements). Said another way, the utility forms plans to do the job it is obligated to do, at minimum cost to customers (assuming full cost recovery). As a form of benefit-cost analysis, cost minimization appears to omit the benefit side of the question. Indeed, the benefits of a non-discretionary project are not usually an issue. If one alternative provides customer benefits that others don't, they can be included, but often the alternatives do not impact customers differently in ways other than utility costs. To summarize, cost-minimization analysis is a limited form of benefit-cost analysis that concentrates on the net change in total utility cost and assumes no change in benefits.

Discretionary Projects (Benefit-cost Analysis)

Projects that directly affect customers' experience of electric service are more complex to analyze. For instance, a project that improves customers' reliability alters the customers' value of service. Projects of this type may be discretionary. That is, if the utility is already meeting its service obligations, it can undertake these service-improvement projects or not. This raises the obvious question of why such a project should be done at all. The answer is found in the balance benefits and costs; the utility may want to undertake an investment if estimated customer benefits exceed the costs. In other words, discretionary projects call for full benefit-cost analysis. As an example, new technology makes it possible for utilities to improve the reliability experience of customers on some feeders or systems of feeders. If the utility invests in the new technology, it adds utility cost while reducing customer interruption cost. Estimates of customer interruption cost can be used to guide these investments, and to estimate where the benefits are sufficient to justify the cost.[11]

In the historical context of vertically integrated utilities, obvious examples of planning studies involve the large decisions such as transmission and generation alternatives. For a utility with the obligation to establish sufficient supply, the analysis of generation or transmission alternatives was typically a cost-minimization exercise using revenue-requirement analysis. Some utilities have included customer interruption costs in the determination of how much reserve capacity the

---

[10] Public and cooperatively owned power companies use a similar method without equity as a financing component. These entities assume all costs are recovered.

[11] It is a legitimate question whether a utility should apply technology where it can, even if the benefits are not sufficient, since all customers will be asked to pay for the technology whether they benefit or not. However, under the initial conditions, reliability experience may vary widely among feeders operated by a utility, and if there is a point of diminishing returns for applying this technology, it is likely to be reached with feeders that already have very good reliability. Investing to improve the reliability on the least reliable circuits brings all customers closer to the same reliability level.

utility should target in its generation planning studies. This type of study is appropriate where the reserve level is discretionary to some extent,[12] and needs to be justified economically.

Utility-planning studies are generally limited to economic results rather than financial results. That is, they establish long-term present-worth costs and benefits, they may include costs and benefits that are not part of the utility-cost function, and most importantly, they are not concerned with the intricacies of cost recovery, rate design, or the timing of rate changes. The implications of economic planning decisions may receive additional study in the financial and regulatory areas of a utility, but the financial and regulatory concerns are not generally built-in to the system planning study methodologies.

Planning studies are not generally referred to as business cases. An integrated resource plan is not a business case, for instance. Consider the analysis balancing reduction of customer interruption costs with the cost of improving reliability. Would this be considered a business case? It might be, but as noted, a business case can mean different things to different people.

Strategic Analysis

Neither utility-planning analysis nor broad benefit-cost analysis re-directs the purpose of a firm; it does not alter the firm's business or its obligation to serve. It generally does not alter the fundamental job assigned to individual business units. Further, an economic study done in one business unit will usually not change or redirect the job done by other business units. Re-directing a firm, altering its overall business model, or even radically altering a firm's internal organization requires a broad self-examination, or a strategic planning exercise. Strategic choices can be examined through a process less precise than benefit-cost analysis, in which alternative future states are examined, in qualitative terms certainly, and quantitative terms if possible. The future states may be a decade or more distant in the future (illustrated in Figure A-4). After the strategic choice is made, conventional analysis methods can be used to optimize the subsequent steps to a desired strategic end-state, as illustrated in Figure A-5.

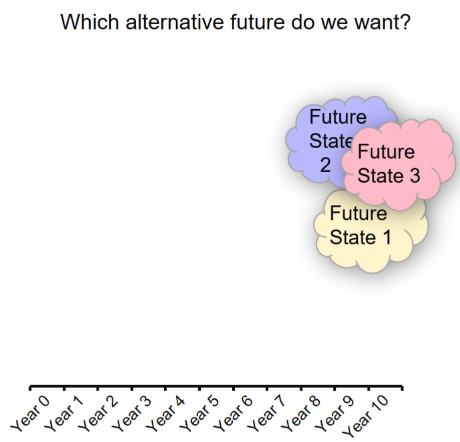


Figure A-4
Strategic Choice Among Alternative Futures

[12] Some states specify a reserve level for planning purposes. Where it is not specified, the reliability constraint obligates the utility to determine the amount of capacity that is appropriate to provide adequate reliability.

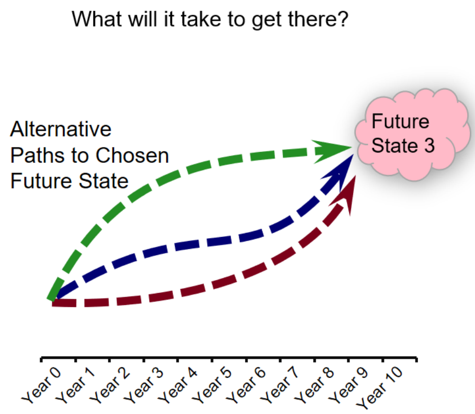


Figure A-5
Subsequent Analysis of Alternative Paths to Future State

Strategic planning processes vary considerably across industries. Beinhocker[13] describes a strategic planning process that first creates "prepared minds" by holding a meeting of upper management to discuss the future, to come to a common mind about the possibilities. This is not a decision-making meeting, but a guided discussion backed by facts gathered beforehand. After management has come to a shared mind about future alternatives, a separate decision-making meeting is held to establish a corporate direction in view of the shared future vision. It is not to "choose a future state," but to assess how to proceed to adapt to expectations of the future.

Strategic choice does not necessarily lead directly to investments and projects in the short term, but may spawn needed organizational changes identified in the process, acting under initiatives to address gaps and study alternatives. An organization may assess its strengths and weaknesses with respect to various gaps that may be identified between where the organization is and where it needs to go. Figure A-6 imagines this kind of analysis as a two-dimensional analysis of helpful or harmful attributes of the organization and the external environment as relevant to the particular objective being considered.

Figure A-6
Objective-oriented SWOT Analysis

---

[13] Eric D. Beinhocker, The Origin of Wealth: Evolution, Complexity, and the Radical Remaking of Economics, 2007.

Clearly a strategic choice that affects the corporate structure requires decisions to be made at a level of management that governs all of the areas involved, including areas that are merely stakeholders. One business unit or organization cannot hope to change a sister organization through its own internal decision-making process. At some management level, all internal stakeholders are represented, and decisions can be made in full view of many alternative viewpoints.

What Kinds of Projects Can Best be Addressed by Different Kinds of Analysis?

To summarize, there are at least three levels of economic analysis for utility decisions. At the local, internal level, an informal business case is often used. That is, a business case can easily deal with decisions where the impacts of various alternatives are within the local zone of control. Such decisions may affect how the utility does its job, especially where alternative tools are available. They often lie in the utility operations domain, described in Figure A-2.

For larger projects that address or extend the utility's obligation to serve, perhaps in a conventional manner, utility-planning analysis may dominate, especially if it is necessary to expand the scope (the "analytic circle") for decision-making to include impacts on customers. Planning analysis is useful when alternative plans and their impacts can be estimated within reasonable bounds of science and engineering informed by experience. The subject matter of utility-planning analysis is often the power system components themselves, which occupy the utility-assets and system-operations domains (Figure A-2).

For alternatives that develop in trajectories that become hazy in the future, perhaps because they are flexible enablers of tools, services, and capabilities that may not yet exist, a strategic framework may help guide the decision-making process. Analysis of fundamental changes in the organization of the firm, the products the firm sells, its vision and values, its public face, these are all matters that can be better addressed in a strategic framework rather than in business-case or utility-planning analysis frameworks.

Export Control Restrictions

Access to and use of EPRI Intellectual Property is granted with the specific understanding and requirement that responsibility for ensuring full compliance with all applicable U.S. and foreign export laws and regulations is being undertaken by you and your company. This includes an obligation to ensure that any individual receiving access hereunder who is not a U.S. citizen or permanent U.S. resident is permitted access under applicable U.S. and foreign export laws and regulations. In the event you are uncertain whether you or your company may lawfully obtain access to this EPRI Intellectual Property, you acknowledge that it is your obligation to consult with your company's legal counsel to determine whether this access is lawful. Although EPRI may make available on a case-by-case basis an informal assessment of the applicable U.S. export classification for specific EPRI Intellectual Property, you and your company acknowledge that this assessment is solely for informational purposes and not for reliance purposes. You and your company acknowledge that it is still the obligation of you and your company to make your own assessment of the applicable U.S. export classification and ensure compliance accordingly. You and your company understand and acknowledge your obligations to make a prompt report to EPRI and the appropriate authorities regarding any access to or use of EPRI Intellectual Property hereunder that may be in violation of applicable U.S. or foreign export laws or regulations.

The Electric Power Research Institute, Inc. (EPRI, www.epri.com) conducts research and development relating to the generation, delivery and use of electricity for the benefit of the public. An independent, nonprofit organization, EPRI brings together its scientists and engineers as well as experts from academia and industry to help address challenges in electricity, including reliability, efficiency, affordability, health, safety and the environment. EPRI members represent 90% of the electric utility revenue in the United States with international participation in 35 countries. EPRI's principal offices and laboratories are located in Palo Alto, Calif.; Charlotte, N.C.; Knoxville, Tenn.; and Lenox, Mass.

Together…Shaping the Future of Electricity

© 2017 Electric Power Research Institute (EPRI), Inc. All rights reserved. Electric Power Research Institute, EPRI, and TOGETHER…SHAPING THE FUTURE OF ELECTRICITY are registered service marks of the Electric Power Research Institute, Inc.

3002010509

Electric Power Research Institute
3420 Hillview Avenue, Palo Alto, California 94304-1338 • PO Box 10412, Palo Alto, California 94303-0813 • USA
800.313.3774 • 650.855.2121 • askepri@epri.com • www.epri.com