# Model-Centric Smart Grid: CBA ORU Case Study

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*"How would a utility's smart grid investment decisions change if they had a detailed integrated network model, and if they could analyze that model leveraging any and all measurement data?"*

Operating predominantly in the state of New York, Orange & Rockland Utilities (**ORU**) is required by the Public Service Commission to provide a Cost Benefit Analysis (CBA) to justify any smart grid investments. Using a single **Integrated System Model (ISM)**, ORU is able to develop a layered investment approach that minimizes the need for expensive "new smart grid devices" while maximizing the use of existing assets.

Standard practice for utilities is to deploy different models, where each model organizes certain data to help solve certain problems. Examples are: GIS – mapping & asset information; OMS – outage tracking and crew management; SCADA/DMS – distribution primary device control; Engineering Analysis – system planning and operations support; TLM – transformer loading; CVR/volt/var optimization – voltage control; P&C – Protection & Coordination analysis; FLISR – automatic fault location, isolation and sectionalizing; and others. Significant capital and operating dollars are spent integrating these systems together so that data can be passed between them, and in massaging data quality among systems. In contrast, the **ISM** provides an environment in which the same model can be used to support many functions, from planning to design to operation to control. Furthermore, since the ISM can incorporate all measurements from independent measurement sets, such as SCADA and customer load, the ISM helps to quickly find data inconsistencies.

> DOE refers to the ORU approach to smart grid as "*model-centric smart grid*", and EPRI has called it "*model-based grid modernization*."

The ISM is built from construction models of the substations, transmission system, and distribution system. This provides a holistic systems approach to the smart grid. The model-centric approach at ORU reuses the ISM from *planning* to *economic analysis* to *lab testing* to *training* to *real-time analysis and control*. DOE has termed this approach *model-centric smart grid*, and EPRI has referred to it as *model-based grid modernization* (1). With the model-centric approach the same model is re-used across functions to process data, even terabyte smart grid data sets, into information.

Models represent an organization of data for some purpose. Algorithms that process the model data are our best tools for turning data, including measurements, into information. Most models today provide data organization for a particular problem, but the hard decisions are still being left to the human mind to figure out by visualizing the data. In contrast, the ISM provides an environment in which badly failed SCADA measurements are immediately detected through the correlation of independent measurement sets (i.e., correlation of historical customer load measurements, customer class load weather dependency factors, and SCADA measurements). Furthermore, reconfiguration for restoration problems can be rapidly solved (e.g., less than a second), avoiding low voltages and overloads, as the feeders affected go through load/renewable generation changes over a specified time of existence for the new configuration (e.g., 24 hours).

In this paper the ISM at ORU is used to investigate value streams from a series of targeted smart grid investments. This model-centric approach to smart grid is expressed by Equation. 1.

$$\textit{Physical Performance} + \textit{Economic Performance} + \textit{Lab Testing} + \textit{Field Pilot Validation} = \textit{Model-Centric Smart Grid} \quad (1)$$

Each term on the left hand side of Eqn. 1 involves the use of the same model, and the terms are evaluated from left to right. For the ***Physical Performance*** term various analyses determine the effects of new smart grid technology on system efficiency, reliability, capacity, controllability, and protection. The variables involved in ***Physical Performance*** are directly measureable, and the ***Field Pilot Validation*** term is used to check the accuracy of the ***Physical Performance*** calculations against field measurements. However, prior to proceeding to the ***Field Pilot Validation*** term, the ***Economic Performance*** term is evaluated, and a decision is made whether to continue with the evaluation of the terms for the particular smart grid technology. It should be noted that the ***Economic Performance*** is not directly measureable as is the ***Physical Performance***, but the ***Economic Performance*** can be estimated based upon the ***Physical Performance*** analysis results.

All available system measurements are used in the analyses to make the ***Economic Performance*** evaluation as accurate as possible, including hourly loads for each customer, hourly cost of energy, hourly equipment failure rates during storms, and others. The hourly measurements are used in time series or quasi-steady state analysis, as indicated in Figure 1. Thus, in analyzing for a year, 8760 evaluations are performed. In the ***Lab Testing*** evaluation hardware-in-the-simulation loop is used to wring out a smart grid device across many scenarios prior to placing the smart grid device into the ***Field Pilot Validation***. Many of the testing scenarios performed in the lab would be difficult, or even impossible, to perform in the field. In ***Lab Testing*** production systems are used as much as possible, including standard software interfaces, communication systems, and the control software that is used in the ORU **D**istribution **M**anagement **S**ystem (**DMS**) that implements the Coordinated Control and Auto Reconfiguration indicated in Figure 1. As part of the discoveries made during the lab testing at ORU, communication issues were uncovered that would have caused the failure of the whole system. Fixing these issues following the field implementation would have been very expensive.

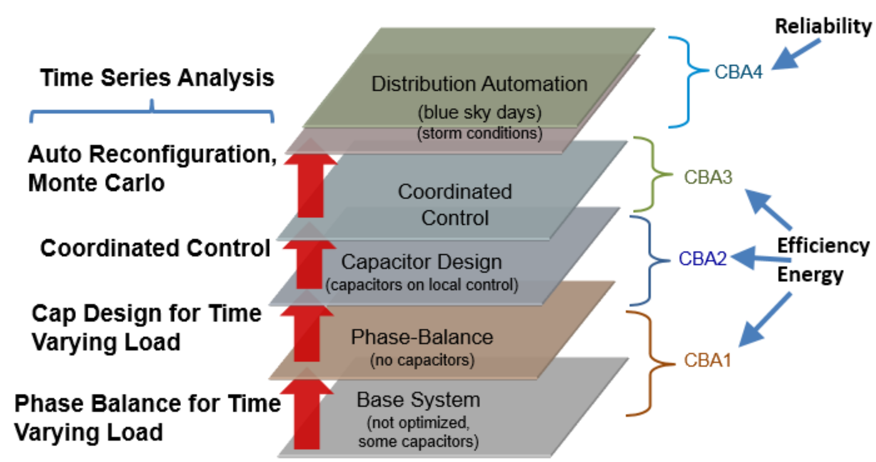


**Figure 1** Dependency Ordering of Investment Evaluations, where decisions made in layer i depend upon decisions made in layer i-1
**CBAi** = Cost Benefit Analysis of layer i relative to layer i-1

A cost/benefit analysis compares at least two alternatives. Quantities associated with an investment scenario must be compared to the same quantities in another "baseline scenario." The model-centric approach uses a layered or incremental approach to the cost benefit analysis, illustrated in Figure 1. In Figure 1, four sequential investments are illustrated, CBA1 – CBA4, where **CBA** = Cost Benefit Analysis. With **CBA1** the ***Physical Performance*** and ***Economic Performance*** of the Phase Balance layer are compared to the Base System. With **CBA2** the comparison is made between the Capacitor Design layer and the Phase Balance layer, and similarly for layers 3 and 4.

Thus, the cost/benefit analysis performed here is structured as a series of economic questions that address the subject in stages or layers. Rather than providing a single lump-sum benefit/cost evaluation for the overall project, the staging of economic analysis provides information about the incremental costs versus the incremental benefits of each stage. The staging also provides the opportunity to incrementally validate the ***Physical Performance***. This layered analysis can expose uneconomic stages that may provide overall benefits. That is, a step that is uneconomic when considered by itself may be necessary to reach economic benefits in subsequent stages, but uneconomic steps that are not necessary can be eliminated or deferred until the economics improve.

Note that the investments of Figure 1 are evaluated based upon a dependency order. That is, the results of the Phase Balance layer will affect decisions in the Capacitor Design layer, and the results of the Capacitor Design layer will in turn affect what happens in the Coordinated Control layer. Without the phase balancing, different sized capacitors, and perhaps more capacitors, may be placed in different locations. The term coordinated control is borrowed from central generation stations, where the various systems (e.g., feedwater, heat source, and steam turbine) are controlled to work together as a team. One of the main benefits of Coordinated Control in central generation stations is the ability it provides to rapidly and smoothly change generation levels without upsetting plant operating states. With smart grid communication systems, Coordinated Control can be used to have control devices work as a team in distribution systems to accomplish one or more objectives.

The ORU Coordinated Control uses a prioritized objective control, where the state of the system can cause the model-based control algorithm to switch objectives. Thus, when the objective is Efficiency/Energy the ORU Coordinated Control uses capacitor banks to improve the feeder efficiency/voltage profile and simultaneously uses LTC's and voltage regulators to implement Conservation Voltage Reduction (**CVR**). If customer load or equipment overload violations occur - as determined by the ORU DMS real-time power flow that solves every SCADA scan calculating voltages and currents for every customer load - then the objective becomes Maximum Capacity. The objective can also be set to just CVR, letting feeder efficiency go.

The ISM integrates all construction models (e.g., GIS or CAD models) together into a single analysis model, and also relates all measurements – customer load, customer load research statistics, SCADA, EMS, weather (historical and forecast), outage, solar generation (historical and forecast), and others – to appropriate equipment or geographical coordinates associated with the ISM. The ISM for the ORU distribution system is illustrated in Figure 2. ORU also models the transmission system in its ISM (not shown in Figure 2). As illustrated in the zoom windows shown in Figure 2, all substation equipment and all sectionalizing devices are modeled, including isolation switches and bypass switches. Such modeling is not normally performed in the most common analysis models used today. Instead, common analysis models are designed to support only one or a few analysis functions, and as such make simplifying assumptions. The ISM provides a foundation for holistic, automated analysis. An ISM creates a collaborative analysis environment that allows different groups within the organization to couple their individual calculations into a larger calculation.

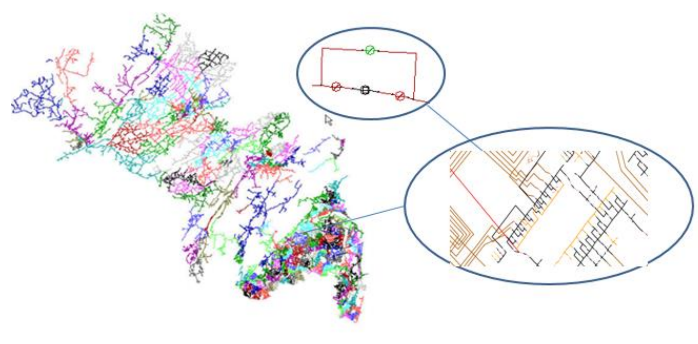

**Figure 2** ORU Distribution System Integrated System Model (**ISM**)

Data, such individual customer load data, is related to the ISM, and the data interface may be shared by many different calculations that run on the ISM. This provides an architecture for data integration and places the data in a context that makes sense. Thus, an ISM can change the paradigm of maintaining many custom data interfaces that "***push data to algorithms***" to a paradigm of maintaining one data interface and “***pushing algorithms to data****.”* This approach to managing data and algorithms that process the data comes from the generic programming paradigm of computer science.

ORU’s ISM is maintained in memory 24x7 on a computer Model Server, and the Model Server can serve up any portion or all of the ISM to analysis requests. Thus, the model-centric approach provides an approach to data integration where interfaces between individual systems are replaced with a standard interface to the ISM. When the data is related to objects in the ISM and/or to xyz coordinates associated with the ISM, it is placed in a context that makes physical sense. With an ISM the need to integrate an “alphabet soup of systems,” creating spaghetti, is eliminated.

ORU can use its ISM to automatically calculate system losses for an entire year over the time varying load pattern. The first time ORU calculated the value of total system losses, the calculated value came to within 0.4% of the measured value. Power flow analysis of the ISM has resulted in finding SCADA measurements that were reading 50% low, avoiding sizing a new substation transformer 50% too small. Finding failed measurement devices is enabled by having both the customer hourly load and SCADA measurements incorporated in and correlated through the same analysis. Via ISM analysis ORU has located failed controllers, has discovered portions of their system that they thought were summer peaking are actually winter peaking, and have analyzed unbalanced voltages in the transmission system (note, the ORU ISM models the transmission system as 3-phase). When the ORU balanced transmission system power flow indicates there are no problems, the unbalanced power flow can report low voltages.

The first two investments shown in Figure 1, Phase Balance and Cap Design, do not involve investments in smart grid equipment, other than a multi-step, individual phase controlled, switched capacitor bank. Instead these investments are considered as preparatory for the smart grid investments of layers 3 and 4. The preparatory investments are made to realize greater value from the investments of layers 3 and 4. The ISM, with all of the measurement data included, allows ORU to take a new approach to the Phase Balance and Cap Design problems, which is to optimize the phase moves and capacitor sizing/ placement against the time varying load. Optimizing for the time varying load results in an improved design over performing the design for just the peak load. The time varying load design still handles the peak, but it provides much improved controllability and efficiency. The cost of the Phase Balance layer was the crew time spent to make the phase moves, and the benefits were improvements in feeder efficiency, reduction in energy to supply the load, and an increase in feeder capacity. The reduction in energy supplied to customer loads occurs because the load is modeled as voltage dependent. The greatest increase in feeder capacity occurred during the summer time, which is the season when the heaviest loading occurs. ORU used measurements from the SCADA system to validate the phase balancing. Figure 3 shows one particular feeder’s validation results, where the phase currents come close together following the phase balancing moves on the feeder laterals.

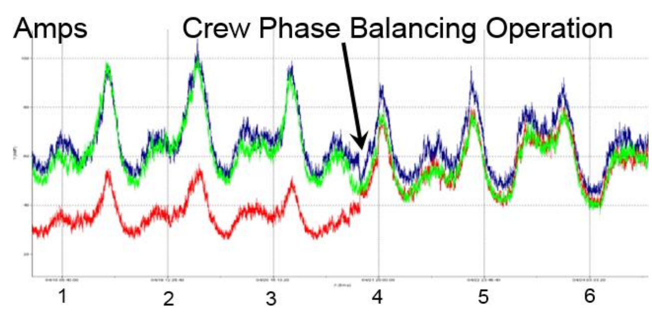

**Figure 3** Phase balancing validation showing phase A (red), B (blue), C (green) currents closely tracking after the phase balancing operation by the field crew

The cost of the Cap Design layer is determined by the cost of purchasing and installing the capacitor banks. The new capacitor banks provided much better control of voltage throughout feeders, and with the improved feeder voltage profile, it was possible to reduce the substation LTC voltage set point by two volts, which provided an energy savings due to the voltage dependency of the load. The benefits from the redesigned Cap Design layer are improvements in feeder efficiency and a significant reduction in energy required to feed the load (due to the decrease in the average voltage), and improved controllability, which benefits the next investment, the Coordinated Control investment. The validation following the Cap Design layer required measuring improvements in power factors at substations. The Cap Design layer contributed to a significant improvement in overall system efficiency, where the overall system efficiency has now been measured at 97.5% for two consecutive years. For some individual substations power factors improved from 93% to 98%.

A 14 feeder system was selected to pilot the Coordinated Control and Distribution Automation (**DA**) investments. To implement the Coordinated Control, communication and actuation devices were placed on the switched capacitor banks, voltage regulators, and LTCs. Coordinated Control calculations performed on the ISM located in the Distribution Control Center provide set points to the automated control devices. To implement the DA layer, 63 automated switches were placed such that each automated switch affects approximately 250 customers. Similar to the Coordinated Control, the automated switches are controlled by calculations performed on the ISM. The automated switches are implemented with low cost devices that do not have software programming and software maintenance requirements. Furthermore, the solution provided by the ISM calculations works for all possible scenarios. In addition, the model-centric approach provides low cost flexibility as renewable generation, electric vehicle loads, and other new technologies such as Community Energy Storage are implemented.

In the ***Physical Performance*** evaluation of the DA layer both "blue sky days" and storm conditions were considered, as indicated in Figure 1. In evaluating the storm conditions Monte Carlo simulations that worked with the production Auto Reconfiguration control algorithm were used. The Monte Carlo simulations were driven by actual historical storm outage data gathered for six different types of storms over a ten year period on the ORU system. Monte Carlo simulations of a given type of storm, such as a high temperature, strong wind storm, would be repeated 6,000 times on the DA layer to arrive at the performance numbers. For a 72 hour type storm, this would result in 432,000 hours of storm simulation. For the "blue- sky" day evaluations SAIFI decreased by 48%, SAIDI decreased by 44%, but CAIDI increased by 18%. The increase in CAIDI results from the customer-minutes for a specific outage approaching from above the number of customer-minutes that would result from the customers that would always have to wait for the full repair.

Figure 4 presents a summary of the ***Economic Performance*** of the 14 feeder pilot system moving through the layers of Figure 1, where the values shown in the table are present worth values for a 10 year period. For the 10 year analysis, load growth and increases in cost of energy are taken into account. The hourly marginal cost of energy was assumed to be the hourly Location Based Marginal Prices for the Hudson Valley load zone in New York, escalated with the price of gas as forecasted by the US Energy Information Administration in the Annual Energy Outlook 2011. The CBAi (i = 1, 2, 3, 4) in the Case column of Figure 4 identifies the costs and savings between layer i and the previous layer, where for the Base System i = 0. Consider CBA2 in the Cost column. The 564

| Case | Cost (Inc/Total) ($000) | Savings Type | | | | | Case Savings ($000) | $ Saved / $ Invested (Inc/Total) |
|---|---|---|---|---|---|---|---|---|
| | | Efficiency (Inc/Total) ($000) | Energy (Inc/Total) ($000) | Capital ($000) | Operation ($000) | CI ($000) | | |
| CBA1 | 163/163 | 94/94 | 29/29 | NA | NA | NA | 123 | 0.75/0.75 |
| CBA2 | 564/727 | 227/321 | 2,234/2,263 | NA | NA | NA | 2461 | 4.36/3.55 |
| CBA3 | 68/795 | 88/409 | 2,064/4,328 | NA | NA | NA | 2,132 | 31.65/5.74 |
| CBA4 | 1,953/2,748 | NA | NA | 7,014 | 7,646 | 9,566 | 24,226 | 12.4/10.54 |

Estimated $CO_2$ reduction = 76,330 tons

Societal Benefits

$1.4 ~ Residential
$230 ~ Commercial
$650 ~ Industrial

**Figure 4** Present Value Savings from Investments over 10 Years
Abbreviations: Inc = increment; CI = Customer Interruptions

represents the investment in the capacitors (i.e., layer 2), and the 727 represents the total investment thus far, which includes the investments for both layers 1 and 2.

The savings shown in Figure 4 are divided into five categories – efficiency, customer energy reduction, savings on alternative capital investments, operations, and customer interruptions (CI). For example, in the efficiency column for CBA2 the 227 represents the savings that accrue just for the investment in the capacitors and the 321 includes the savings from both layers 1 and 2. Consider the $Saved/$Invested column for CBA3. The 31.65 indicates that for the layer 3 investment there is $31.65 saved for every $1 invested where just the layer 3 investment is considered (i.e., the difference between the Cap Design and Phase Balanced systems), and the 5.74 indicates that there is $5.74 saved for every $1 invested considering the total investment thus far in layers 1-3.

Societal benefits are also summarized in Figure 4. CO2 reduction over the 10 year period is estimated to be 76,330 tons. The DOE Interruption Cost Estimate Calculator was used to calculate customer savings from reduced interruptions. As shown in Figure 4, residential customers saved on average $1.40, commercial $230, and industrial $650 (note these figures are on an annual basis).

From Figure 4 it may be seen that for the CBA1 investment there is only $0.75 saved per $1 invested. The feeders considered for the 14 feeder pilot system are around 5 miles in length. For significantly longer feeders, this investment lost would often not occur with phase balancing. Even though over the 10 year period considered there is a dollar loss with the CBA1 investment, it was decided that the effects on subsequent investments would be significant, providing a balanced system for the Cap Design and a more controllable system for the investments in Coordinated Control and DA. Furthermore, with the growth of single-phase solar energy generation on the ORU distribution system, maintaining a balanced system is even more important.

DA benefits arise from deferrals of system capital equipment upgrades that would have otherwise been required to maintain reliability within planning criteria. This category is referred to here as "Planning Response," which lowers the cost of providing reliable electricity service to customers. Planning response produces "hard-dollar" savings over a period of time, beginning when upgrades are deferred from the base case. DA benefits also arise from operational savings, especially during storm response.

CBA1 – CBA3 investments affect feeder efficiency and energy supplied to the load. The CBA4 investment affects reliability. It should be noted that the savings associated with the reliability investment; $24,226,000, are very large compared to the savings from CBA1 – CBA3. However, it should also be noted that the savings realized in CBA4 are dependent upon the CBA1 – CBA3 investments. For instance, the Coordinated Control is needed for changing local control device set points as the system is reconfigured by the DA, maintaining the optimal operation of the system as it is reconfigured.

With many smart grid investments made today, measurement data at both the transmission and distribution levels is going into storage and is not being turned into information. But how do we turn data into information? Scientists and engineers use models to turn data into information. An ISM with all measurement data related to it provides an environment that supports all traditional analysis and a pathway to advanced analysis, the results of which can be used for improving decisions, including both investment and operational decisions. The ISM is reused from planning to real-time operations.

Model-centric smart grid provides a cautious approach to the implementation of smart grid technologies. Model-centric smart grid decisions are based upon information obtained from detailed analysis driven by available measurements. Prior to investing in smart grid devices or systems, ISM analysis can be used to compare the ***Physical*** and ***Economic Performance*** of alternative investments, and to evaluate dependencies among the investments. ***Lab Testing*** of the most promising investment(s) using hardware-in-the-ISM-simulation loop can then be used to check the operation across many scenarios. If the lab tests are successful, then a ***Field Pilot Validation*** can be performed where the ***Physical Performance*** calculations are validated. These evaluations, from ***Physical Performance*** to ***Field Pilot Validations***, are performed with a layered investment strategy, as illustrated by Figure 1, where Eqn. 1 is applied to each layer in turn.

The concept of an ISM has been likened to a "***living model***, where the ISM undergoes continuous improvement." The ISM is built from construction models, and in the ISM world the "***best equivalent is no equivalent.***" An ISM has also been likened to a "***manufactured model***," where many experts that do not even necessarily know one another contribute to the ISM. Many, if not all, analysis models in use today are maintained by one or a very small group of analysts. An ISM avoids integrating data across "an alphabet soup of systems," creating spaghetti, that solves a few functional problems that were envisioned prior to the integration, but is expensive to expand when the problem landscape changes. An ISM provides a holistic systems approach to the smart grid.

In other industries it has been demonstrated time-and-time again that automation makes financial sense. Similar to these other industries, model-centric smart grid automation makes financial sense for the ORU distribution system. Today ORU is not the only one pursuing ISMs. Utilities, from municipals to large investor owned, are building ISMs to solve problems that cannot be solved with traditional analysis models. The ORU model-centric smart grid solution provides more than a self-healing system - it provides a self-healing system that is operated optimally.

**References**:

1- "Analysis of the Costs and Benefits of Model-Based Grid Modernization for Orange and Rockland Utilities," EPRI report.