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DEMAND RESPONSE ANALYSIS AND CONTROL SYSTEM PHASE 1 FINAL REPORT

A Report on Lessons Learned and Next Steps

Prepared For:
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Prepared By:
EnerNex Corporation



PIER FINAL PROJECT REPORT

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Approvals

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Preface

The California Energy Commission's Public Interest Energy Research (PIER) Program supports public interest energy research and development that will help improve the quality of life in California by bringing environmentally safe, affordable, and reliable energy services and products to the marketplace.

The PIER Program conducts public interest research, development, and demonstration (RD&D) projects to benefit California. The PIER Program strives to conduct the most promising public interest energy research by partnering with RD&D entities, including individuals, businesses, utilities, and public or private research institutions. PIER funding efforts are focused on the following RD&D program areas:

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- Energy-Related Environmental Research
- Energy Systems Integration
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- Renewable Energy Technologies
- Transportation

Demand Response Analysis and Control Report is the final report for the Demand Response Analysis and Control project by EnerNex (Contract Number CEC-500-DR08-02), conducted by EnerNex and Oak Ridge National Laboratory. The information from this project contributes to PIER's Energy Systems Integration Program.

For more information about the PIER Program, please visit the Energy Commission's Website at www.energy.ca.gov/research/ or contact the Energy Commission at 916-654-4878.

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1.0 Executive Summary

1.1. Project in Brief

This document meets the deliverable requirement for Task 5, Develop Final Report for a Demand Response Analysis and Control System (DRACS) for Research Opportunity DR ETD-02-01. The grant was provided to the EnerNex team to address two research topics and questions identified in the opportunity notice:

- “Using a military (or another, such as air traffic control) C3I (Command, Control, Communication, and Information) system as a model, adapt it to conceptually deal with C2I electricity applications such as dispatching DER to keep the lights on. Compare and contrast the chosen C3I model with the requirements for implementing a C2I strategy for integrating utility control, communications and information systems. Are there analogies that indicate utilities can operate in a similar fashion? If not, what are the gaps that need to be filled and is it feasible to fill the gaps?”
- Given current utility systems and assuming the systems are integrated, how would the CAISO or an UDC operate its control centers in a military (or another) C3I style? With up-to-date real-time information and the ability to control all of its available assets, given a particular operational scenario, how would a plan to address the scenario be executed using strategies based on military (or another) C3I?”

This report is based on careful studies, close interaction with San Diego Gas & Electric stakeholders, and coordinated efforts between EnerNex Demand Response experts, the Open Smart Grid AMI Enterprise team, and C3I system engineers at Oak Ridge National Laboratories (ORNL).

1.2. Project Approach

This project was broken into two phases. The first phase is the research portion of the effort, and this report is directed towards the efforts conducted during the phase one activities. The second phase is proposed for the future, and is discussed in more detail in the Recommendations section of this document.

The first phase of this project consisted of the following tasks and deliverables:

1.2.1. Task 1 – Develop Requirements for a Demand Response Analysis and Control System (DRACS)

This task involved the development of traceable and defensible requirements for command and control systems capable of operating systems with high penetrations of demand responsive load. This task utilized the use case based methodology for requirements capture developed by the EPRI IntelliGrid Consortium, the same methodology used at Southern California Edison for the AMI requirements development. The EnerNex team conducted a workshop with utility and industry demand response stakeholders. Where possible, existing use cases, message traffic models, and related information developed for SCE’s AMI project were utilized.

Deliverable: DRACS Requirements Document

1.2.2. Task 2 – Develop Requirements for a platform to simulate the behavior of the DRACS

This task utilized the same methods for requirements capture applied in Task 1 but for the purpose of determining what information, models, and algorithms are necessary to simulate the behavior of the DRACS. The platform is intended to be used to evaluate the overall stability of the power system when large amounts of demand responsive load change state in short time periods under the control of communication networks with large and highly variable latencies.

Deliverable: DRACS Simulator Requirements Document

1.2.3. Task 3 – DRACS Architecture and Reference Design Development

This task involved the creation of an architecture and reference design for a generic DRACS based on the requirements captured in Task 1. The reference design provides discussions of the Demand Response Management System (DRMS) parent system, DRACS design considerations, architectural strategies, the reference architecture and design, and architectural policies and tactics.

Deliverable: DRACS Reference Architecture Document

1.2.4. Task 4 – Simulation and Stability Analysis Platform Framework Development

This task developed the framework for a simulation and stability analysis platform suitable for testing a DRACS and evaluating its performance based on the requirements captured in Task 2. This platform will consist of a combination of commercial and freely available software to be configured in a laboratory environment in Phase 2. The document resulting from this task will describe the simulation platform framework, the tools and components that constitute the framework..

Deliverable: DRACS Simulation Framework Document

1.2.5. Task 5 – Phase I Report

The Phase 1 report documents the key findings of the Phase 1 research. The focus of the report is to provide background on the activities conducted, provide details on what was learned, and make recommendations for going forward with a Phase 2 effort.

Deliverable: Phase I Final Report Document

2.0 Findings and Results

The DRACS Phase 1 project provided EnerNex team members with the opportunity to talk with many demand response experts and incorporate the EPRI IntelliGrid use case analysis methodology to deeply explore and analyze DRACS requirements, reference architecture, simulation requirements, and simulation framework. The results and findings of this effort are captured below, some profound, others fairly obvious, but all architecturally-significant or at least worthy of mention.

2.1. DRACS Relationship to Demand Response Management

The DRACS system can be viewed as a sub-system or module within the Demand Response Management System (DRMS).

2.1.1. DRACS Module Components

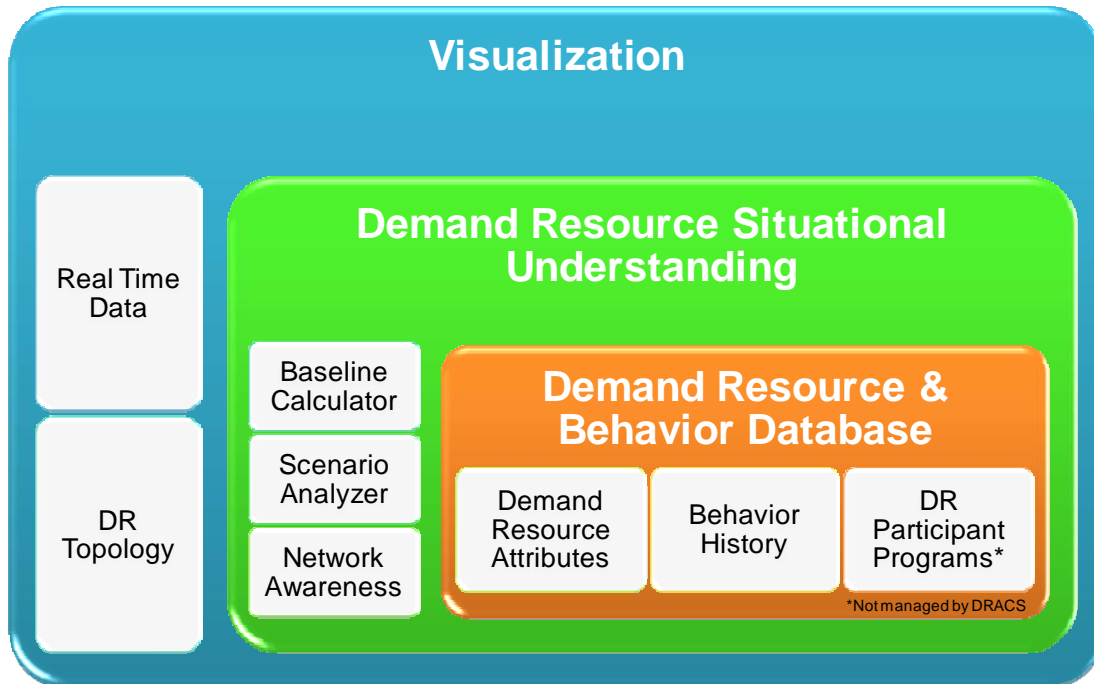


Figure 1: DRACS components

There are three (3) primary components within the conceptual DRACS architecture as depicted in Figure 1 above:

1. Demand Resources and behavior database – this relational database houses Demand Resource information such as the device type, service type, customer ID, path/topology information, enrolled customer programs, maximum load, normal load, GPS location, and any other attributes pertinent to understanding the location and load profile of the resource. In addition, the database also houses behavioral patterns of the resource based on historical data. Also, DR event data is stored to understand the system's expected response vs. the actual response for each DR event. The existence and required maintenance of this database implies an import capability that periodically

captures behavior, and provides a mechanism for adding and removing Demand Resources.

2. Demand Resource Situational Understanding – this analytical tool is the heart of the DRACS system. It receives a scenario from the DRMS system, analyzes the scenario requirements against the Baselines and current network environment, historical behavior, and real time conditions, and then returns the probability of success to the DRMS system.
3. Visualization – the visualization component provides the operator with a real time topological view of the demand response landscape. It also provides the operator with a view of real time network events and a drill up/down capability for any Demand Resource that exists in the DR topology.

2.1.2. DRACS Information and Decision Flow

Figure 2, below, depicts a simplified DRACS architecture provided to show the critical functionality, and decision and communication flow that occurs within DRACS. There are 3 different information and decision flows within DRACS. They include:

1. Network Status and Load Information
2. Demand Resource Attribute and Behavior Information
3. Scenario Confidence Information

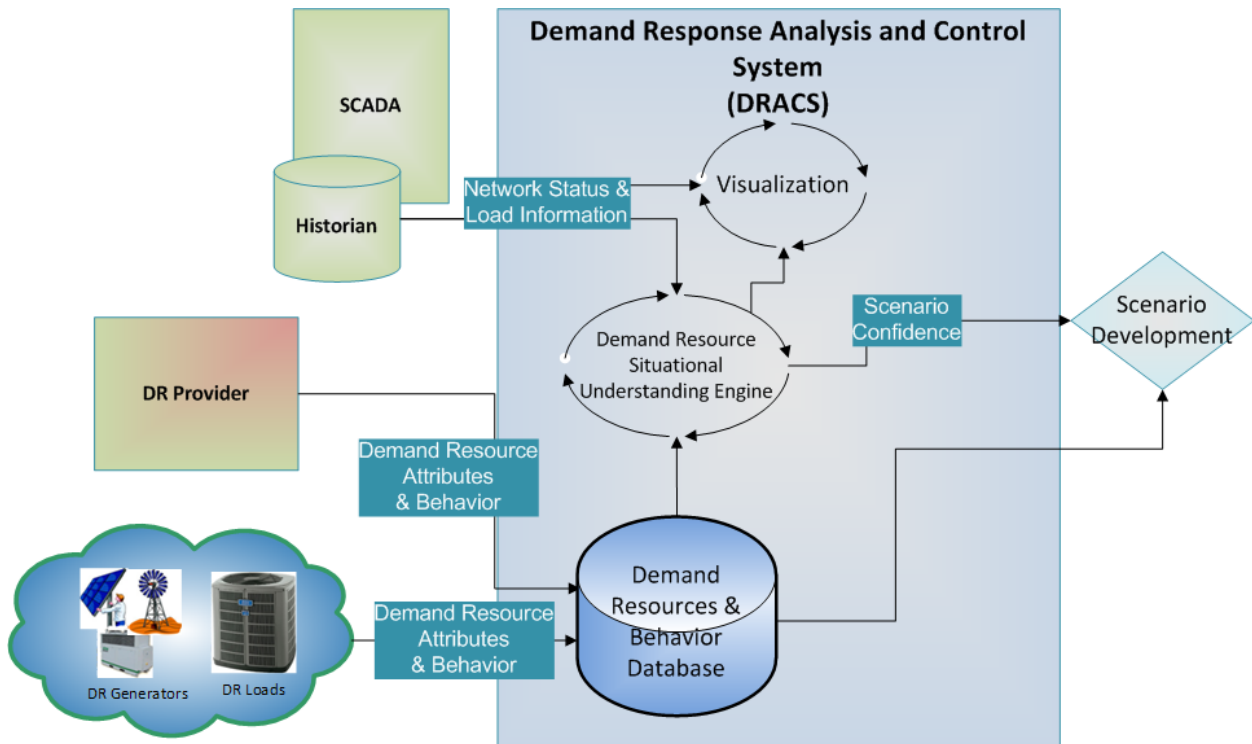


Figure 2: DRACS Block Diagram - Information and Decision Flow

2.1.3. Demand Response Management System (DRMS) Relationship

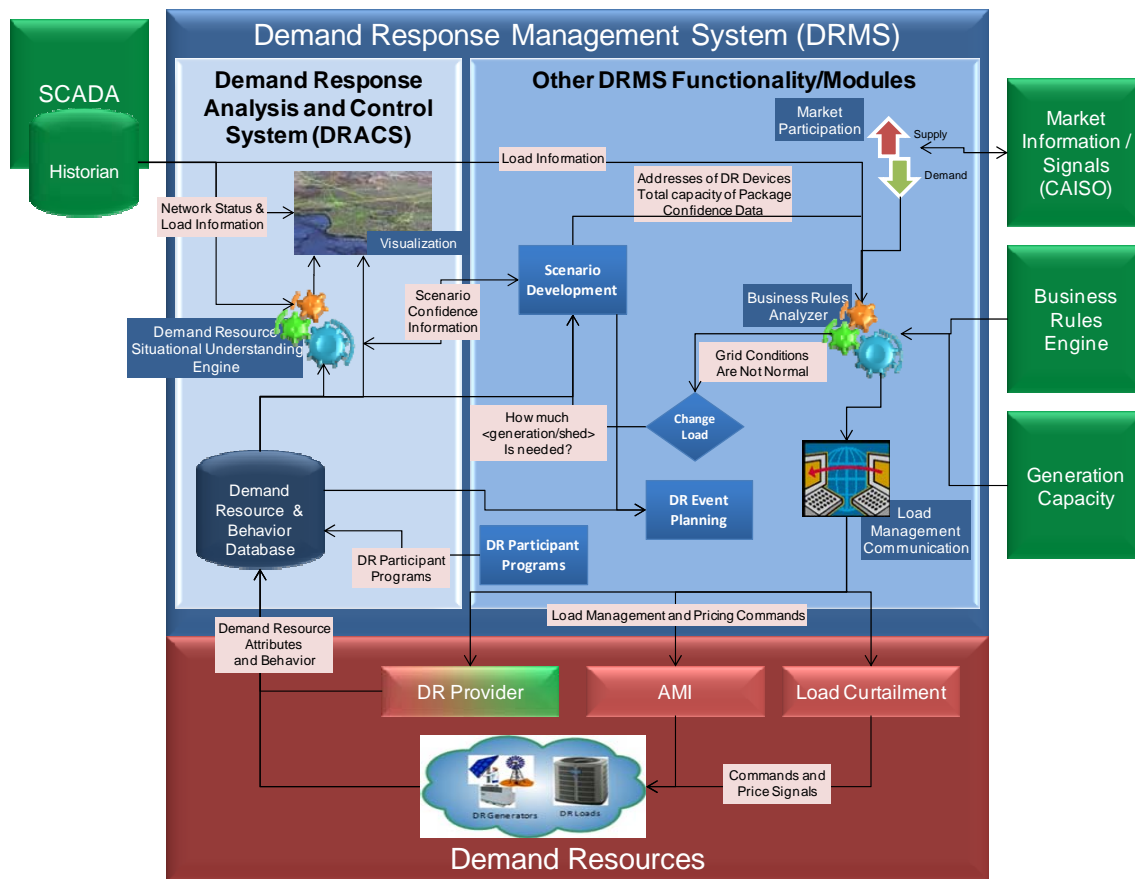


Figure 3: DRMS Block Diagram – Information and Decision Flow

The DRMS was out of scope for the DRACS project. However, it is important to understand the parental relationship of DRMS to DRACS. The DRMS is the overall management system for the demand response environment. It is responsible for *balancing* the energy supply and demand over a portion of the grid. In fact, a better description from Demand Response Management System might be an “Energy Balance Management System”, or it might also be combined with existing Distribution Management Systems (DMS). In addition to the situational understanding functionality supported by DRACS, this includes making business decisions based on business rules on how, who, what, when, and where demand events occur. These business rules can be used for both real time DR events or in planning for day-ahead events. Based on these business rules, the DRMS is responsible for developing the optimal scenarios/combinations of demand resources for addressing each demand response event. Additionally, the DRMS communicates with these demand resources through systems such as AMI, legacy load control systems, and contracted DR providers.

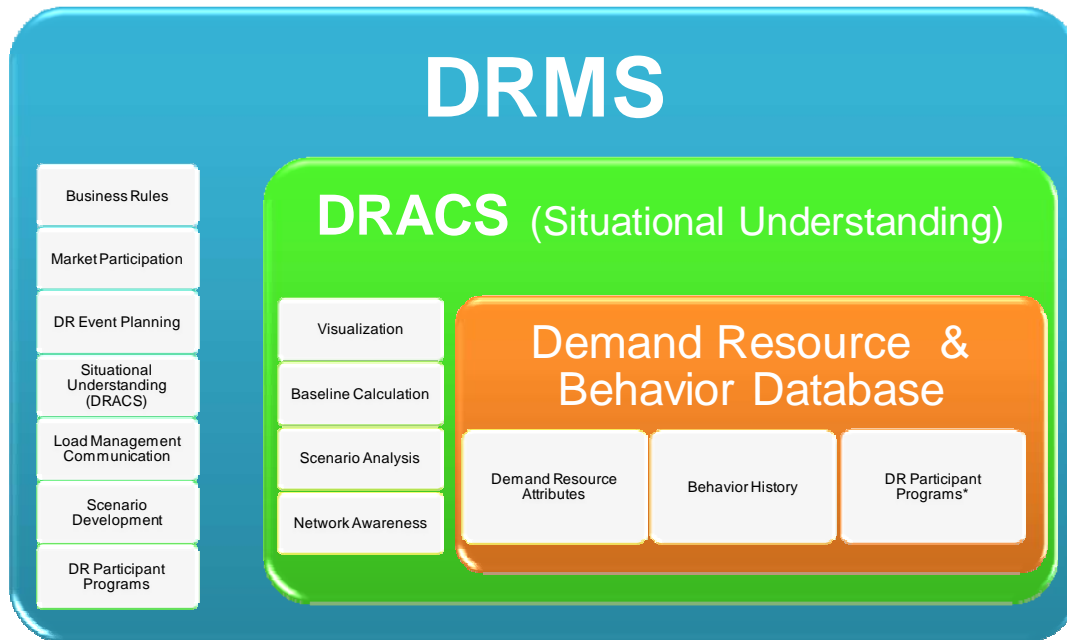


Figure 4: DRMS-DRACS conceptual relationship

Figure 4, above, shows the conceptual relationship of DRACS to the DRMS system. DRACS is one of the 7 modules within DRMS. The 7 modules include:

1. Business Rules Analyzer. This module uses business rules to determine when DR events should be initiated.
2. Market Participation. This module performs energy market analysis and management.
3. Demand Response Event Planning. This module performs day-ahead planning used to pre-select and optimize DR scenarios for known events.
4. Situational Understanding (DRACS). DRACS provides the real time demand resource and DR topology situational understanding and evaluates DR scenarios for probability of success.
5. Load Management Communication. This module provides the communication link to the various load management systems.
6. Scenario Development. This module uses business rules and DRACS simulator information to develop DR event scenarios.
7. DR Participant Programs. This module supports the management of demand response programs within the organization.

2.2. DRACS Visualization

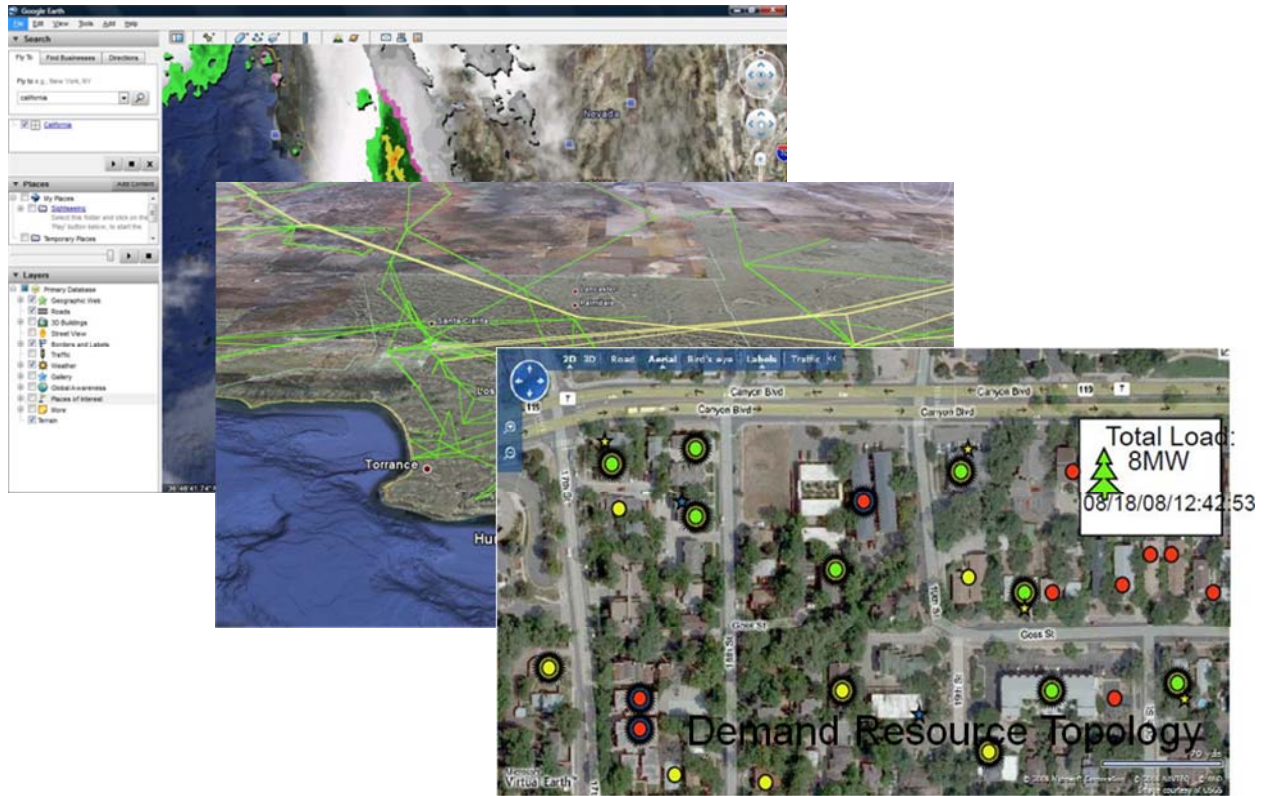


Figure 5: Real Time visualization capabilities for DRACS are a critical architectural requirement

The visualization capabilities of DRACS are two-fold. First, DRACS provides a visual representation of the overall demand response topology. This entails a hybrid visualization of the grid, streets, terrain, landmarks, weather, and demand resources.

DRACS visualization of the demand response topology also needs to include the participants and Demand Resources within the DRACS operator's territory. The map depicts the network topology with multiple layers that can be switched on or off, including those for terrain, Demand Resources, and participants. The overall visualization requirements are to show where the energy is, where it is being used, and where it is needed in order to support the situational understanding of the Demand Response topology. Icon shape and relative size describe the type of participant and Demand Resource and their Baseline or generating capabilities. A search tool allows the operator to filter participants or Demand Resource assets by asset class, size of load management capability, location, service type, Demand Response program, Demand Response system, and Demand Response event.

The second visualization capability of DRACS is in providing real time distribution network topology information visualization and key performance indicators (KPI). Loads, temperature and other weather data, outages, congestion, voltage loss, and other pertinent information which can affect the ability to support a DR request are shown as more switchable layers on the topology map or as separate instrumentation "panels" on a separate screen. A successful

DRACS visualization tool merges the demand response topology and the pertinent real time data.

2.3. DRACS Scenario Analysis

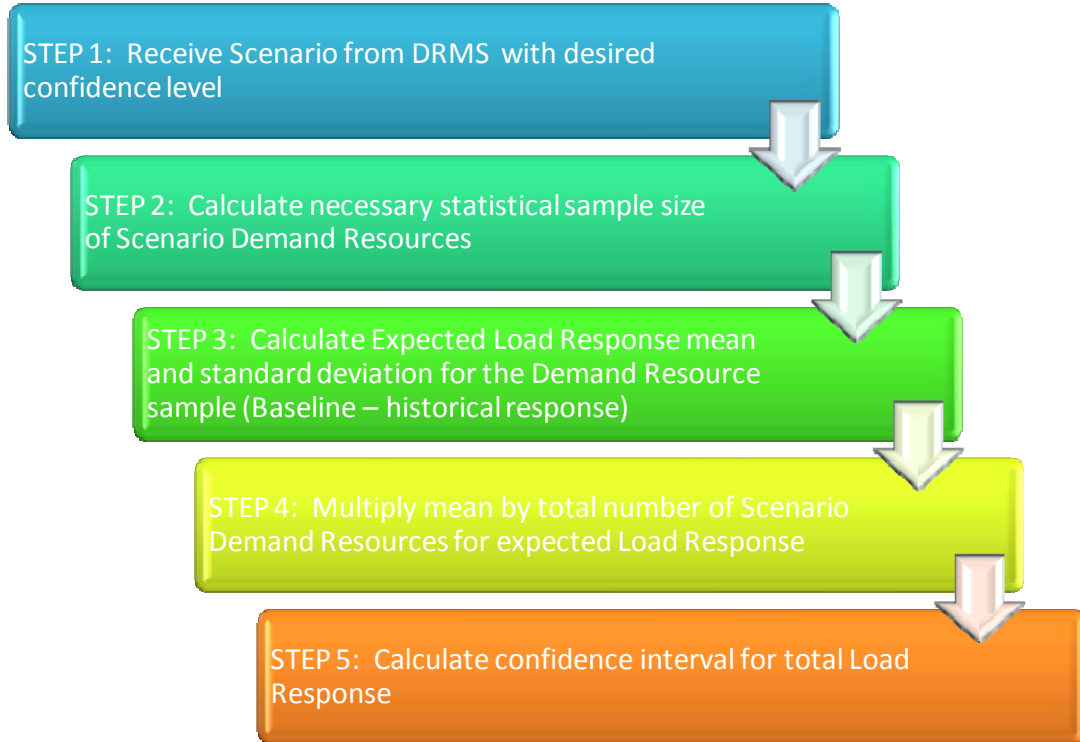


Figure 6: DRACS computes confidence intervals using statistical methodologies in evaluating scenarios

One of the primary objectives of the DRACS operational system is to provide scenario confidence intervals for meeting DR event requirements in real time. Figure 6 shows the steps for creating Baseline Confidence Intervals for evaluating Demand Response scenarios. DRACS receives a scenario, population total, and expected Confidence Level from other modules within the DRMS. DRACS determines the statistically-significant sample size. Next it calculates or retrieves Baseline information for the sample set and calculates the expected Load Response based on historical or empirical data. The expected Load Response calculation is the “secret sauce” and the reason DRACS requires a true “situational understanding” of the Demand Response landscape. It will use historical data, current electrical network status, weather, social response algorithms, communication loss and latencies, and any number of other proprietary algorithms to accurately predict the expected Load Response for the scenario. DRACS uses all this information to calculate the expected Load Response mean and standard deviations. The final step returns the total expected Load Response and Confidence Interval to the requesting module in DRMS. This may also include metering guidance (frequency of readings, locations, etc.) to verify the required load response.

2.4. DERs and Demand Resources

2.4.1. Nomenclature confusion with DERs and Demand Resources

One of the revealing aspects of the DRACS project analysis was observing simple nomenclature conflicts. The team settled on the North American Energy Standards Board's (NAESB) terminology, not because it was the best or most accepted, but because it was published and relatively defensible. Unfortunately, even with this approach, there is still confusion. According to NAESB, the following definitions apply:

- Demand Resource. A Load or aggregation of Loads capable of measurably and verifiably providing Demand Response.
- Demand Response. A temporary change in electricity consumption by a Demand Resource in response to market or reliability conditions.

Our interpretation of Distributed Energy Resources (DERs) in the NAESB nomenclature is that Demand Resources are the opposite of DERs, where DERs provide energy generation capabilities (dispatchable renewable energy resources, small generators, stored energy) and Demand Resources provide load reduction capabilities. Clearly, this is not everyone's understanding of DERs, where many feel that Demand Resources and Distributed Generation (DG) devices are different forms of DERs. But, for the purposes of the following discussions, we consider DERs as dispatchable supply resources (electricity generators) and Demand Resources as dispatchable loads.

2.4.2. Managing DERs and Demand Resources with the Same DRMS System

One of the interesting findings from the DRACS project is that all Demand Resources and Supply Resources (DERs) may be managed within the same system and set of applications, regardless of what you call them.

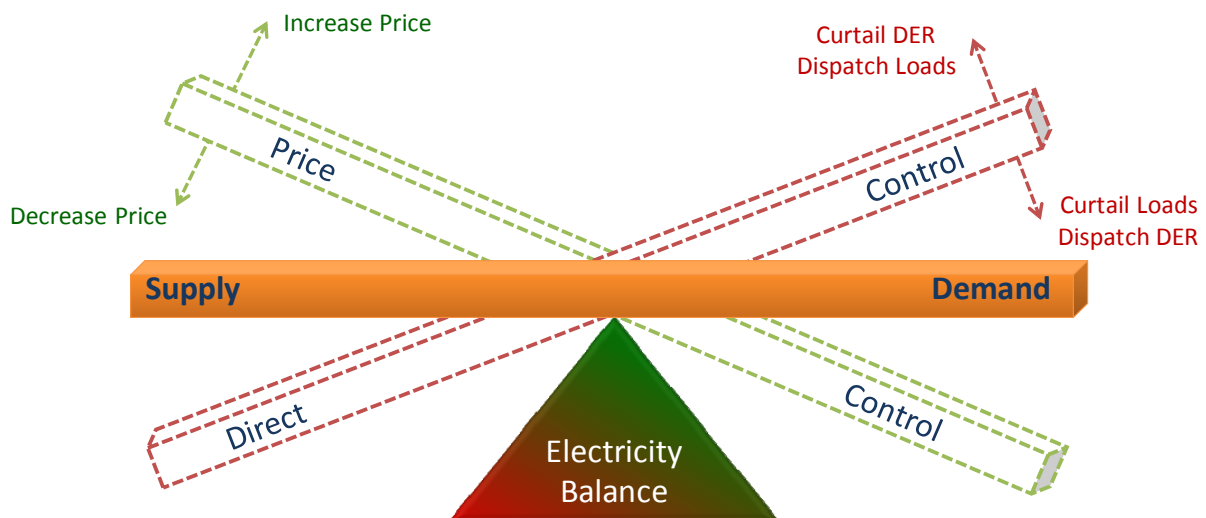


Figure 7: Electricity balance may be controlled by price or direct control signals

As depicted in Figure 5, above, electricity balance of supply and demand may be achieved through price or direct control signals. Most Demand Response discussions focus around the

load management side of the equation, and the supply side is either ignored or is considered a different problem, set of systems, and set of applications. This is not at all accurate, and when considering whether to increase or decrease demand, business rules, market conditions, or other constraints (such as weather, grid conditions, societal benefits, etc.) may better support the exact opposite – the decrease or increase of supply.

The concept of using a single set of systems and applications to manage both Demand Resources and DERs is both sound and practical. If all dispatchable resources are managed through the same systems, the likelihood of generating device and load device systems counteracting one another is eliminated. Perhaps even more important is the fact that as these systems mature and historical behavior patterns emerge, energy managers and providers can “learn” from that history and develop optimized approaches for energy balancing situations over time.

The mix of DER and Demand Resource device management under one roof allows 6 different means for balancing the energy supply and demand; 2 pricing mechanisms and 4 direct control mechanisms:

1. Decrease Price. A reduction in price will have the effect of increasing demand and decreasing supply. Energy consumers will want to buy more electricity at lower prices. Energy suppliers will have less incentive to sell at the lower prices.
2. Increase Price. An increase in price will have the effect of decreasing demand and increasing supply. Energy consumers will want to buy less electricity at higher prices. Energy suppliers will have more incentive to sell at the higher prices.
3. Curtail Loads. A direct load curtailment signal will decrease the electricity demand. This is the most common way people think about demand response. It is direct controls to demand resources requesting/demanding energy usage reduction.
4. Curtail DERs. A direct curtailment of DERs will decrease electricity supply. In the event there is too much supply, DERs may be signaled to stop feeding supply into the grid.
5. Dispatch Loads. A direct load dispatch signal will increase demand. This is particularly useful in situations where renewable resources such as Photo-Voltaic (PV) or Wind generators are present and increased loads are needed to optimize their usage.
6. Dispatch DERs. A direct DER dispatch signal will increase supply. In the event of traditional bulk generation losses or shortfalls, direct signals may be sent to dispatch DERs to provide additional electricity supply to the grid.

2.5. Active versus Passive Demand Response Management

One of the early debates of the DRACS project was whether the system should perform a handshake with Demand Resources when initiating a Demand Response event. This was a highly debated topic, and after much discussion, the team with help from California utility partners agreed that a passive system made the most sense.

With the vast number of demand resources expected to enter the marketplace (with large quantities of demand resource consumer device sales at retail stores a distinct possibility), and with the expectation that bi-directional communication may occur between the DRMS and some of the devices out in the field, we think that in the nearer term such systems are likely to first move through a passive rather than an active management phase. It is also unlikely initially that a 100% accurate list of devices, their capabilities, baselines, and their addresses will exist when DR events are kicked off. To date the implementation of real-time feedback of customer loads from a large number of smart meters is not supported by current technology.

Finally, past behavioral information will certainly help in predicting DR event responses, but there are many variables that will induce uncertainty into the response predictions. Therefore, it makes sense to have a DRMS system that sends DR commands, then using the DRACS module, passively monitors the system on how it responds, at least for residential customers (with potentially millions of demand resources and small per unit load reduction capabilities). The DRMS should not send commands, wait for responses from all the devices, then react based on those responses. There are simply too many devices and too many communications and human behavior issues that will make this level of handshaking overly complex and potentially error-ridden in the beginning. Instead, the DRMS should observe the system's reaction to the DR event commands and fine tune and send additional signals based on actual response.

The exception to this line of thinking is where large consumption/supply changes may occur, such as C&I customers or an energy service provider/aggregator. In instances such as these, it is logical and practical to have the full handshake and tightly coordinated approach to the DR event in order to avoid over or under-shooting DR event needs by large amounts. AutoDR is a likely candidate technology to utilize in this situation, and can be incorporated into the overall DRMS system and event strategy as one of potentially several load management systems it oversees.

2.6. DRACS Scenario Analyzer/Simulator

2.6.1. Simulator Operation Modes

A key component of DRACS is the simulation engine. By clarifying the role of this component, we provide designers insight into the construction of the engine. The "simulator" within DRACS performs scenario analysis and provides design simulation capabilities. The scenario analysis function in DRACS is a "run-time" operational feature responsible for evaluating DR scenarios against DR events in real time. It is responsible for analyzing requests for blocks of energy, capacity, reserves, or ancillary services and providing a predictive confidence level for success in meeting the requested DR event with the set of available mechanisms and real-time state.

There is also an "off-line" simulation feature that evaluates expected DR penetration, scope of dispatch strategies, range of behaviors, etc. in varied scenarios (including worst-case). Here the goal is to determine what strategies need to be designed and made available within the system prior to the actual DR event. This simulation feature is useful when there are planned DR events, and multiple scenario responses may be simulated and evaluated. The simulator

functionality overlaps with the scenario analysis run-time module. The run-time module must handle a specific case, and thus needs more accurate current event information. The off-line simulator exercises a broad set of response scenarios and hence some of the inputs may be generalized and the event conditions are predicted, rather than actual. Both the “off-line” and “run-time” simulator have the same sub-modules and operate effectively in the same manner, but their functions are different in that the “run-time” simulator evaluates one scenario at a time in real time, and the “off-line” simulator evaluates multiple scenarios and “scores” them for their ability to meet a future DR event’s requirements.

To summarize:

- Off-line Analysis Mode. Simulation of DR penetration and behavior. This involves a state space search of the various scenarios that can take place in the CAISO-based DR system. These simulations take a form of “worst-case” and “average case” analysis.
- Run-Time Analysis Mode. Also called Scenario Analyzer. Evaluation of DR specific scenario. This simulation step involves a specific scenario unfolding in the CAISO or at the utility. This is more of a “contingency” form of analysis.

2.6.1.1. Off-Line Analysis

In the off-line capacity, the simulator primarily functions as a planning tool. In this mode, the simulator answers questions such as: If DR penetration goes up to 20%, does the system become unreliable? Given a certain customer behavior profile, does the DRACS dispatching help? How much should be dispatched? Given delays encountered in the monitoring and communication system, can DRACS send the system into instability? What parameters is the system most sensitive to (delays, loads, behaviors, topology, etc.)?

This analysis requires modeling the power system scenarios for classes of scenarios that represent aggregate demand-response penetrations, broad buckets for customer behavior profiles, general mechanisms for dispatch, and expected distributions for communications delay, dispatch latencies, etc. This analysis can use power flow solver simulations but is often feasible with analytical formulations that capture the conditions of interest. Although analytical formulations are feasible, the input parameters as requirements to the simulator overlap with the operational on-line computation piece described in the next section.

2.6.1.2. Run-Time Analysis

The on-line behavior of the simulator must assist in ensuring the DRACS system effectively meets specific DR event requirements in real time. These are summarized in the following steps.

1. Observe (and visualize) real time network information network-related events (outages, voltage loss, etc.).
2. Retrieve and analyze information on available demand responsive resources.
3. Retrieve and analyze behavioral information.
4. Receive and analyze scenarios for compliance with DR requests.

The simulator's operation in real-time takes data collected and stored in the first three steps listed above (supported by the overall DRACS system) and gives the results and guidance for step 4.

2.6.2. Simulator Functional Components

Figure 6, below, shows the DRACS Scenario Analyzer/Simulator.

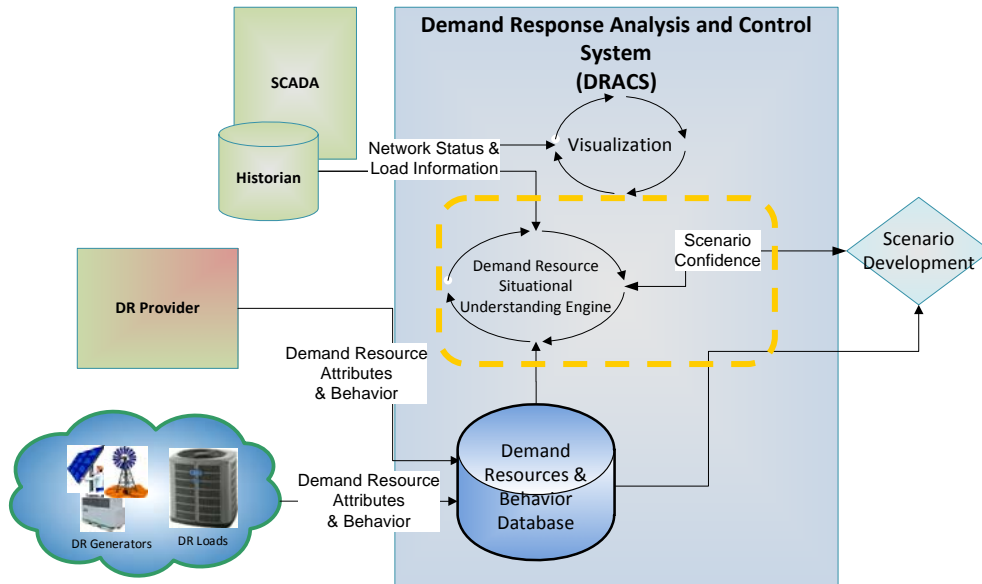


Figure 8: DRACS Architecture Components

The conceptual framework within the simulator is illustrated in the figure below:

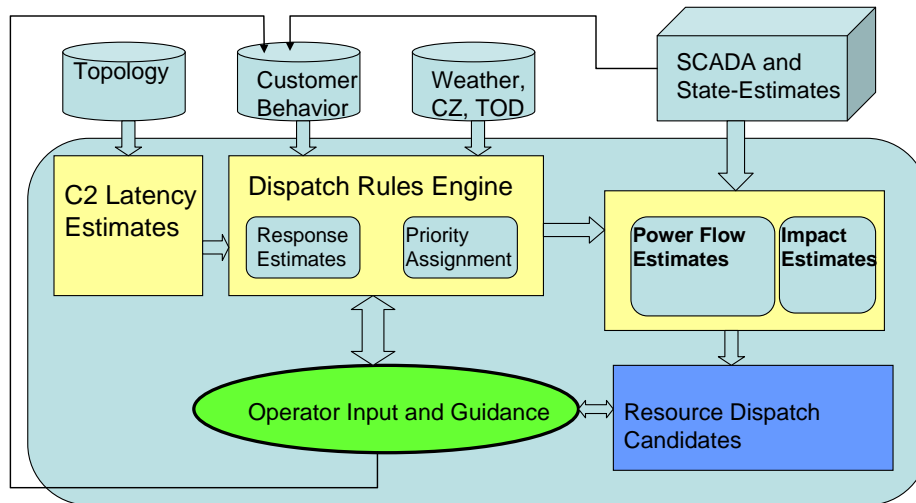


Figure 9: Operational Flow in Simulator Components

The operational flow of the run-time simulator function is illustrated by the flow of data from the databases through the solver and into an operator feedback and control tool.

The DRMS generates scenarios for managing each DR event. These scenarios are built based on business rules and from a collection of Demand Resources in the Demand Resource Attribute and Behavior database that meets both the business rules and DR event requirements. DRACS receives a scenario from the DRMS. The simulator's on-line analysis function evaluates the scenario against the collection of Demand Resources Baseline estimates and previous behavior, current electrical network events, and topology communication and social response algorithms and calculates the likelihood of success in meeting the DR event objectives. DRACS compares against "Baseline" values which are estimates of the electricity that would have been consumed by a Demand Resource in the absence of a Demand Response Event. Depending on the type of Demand Response product or service (one of energy, capacity, reserve, or regulation service), baseline calculations may be performed in real-time or after-the-fact. The baseline is compared to the desired metered electricity consumption during the Demand Response Event to determine the Demand Reduction Value. There are three Types of Baseline Models:

1. Baseline Type 1 (Interval Metered) - A Baseline model based on a Demand Resource's historical interval meter data which may also include but is not limited to other variables such as weather and calendar data.
2. Baseline Type 2 (Non-interval Metered) - A Baseline model that uses statistical sampling to estimate the electricity consumption of an Aggregated Demand Resource where interval metering is not available on the entire population.
3. Behind-The-Meter Generation - A performance evaluation methodology, used when a generation asset is located behind the Demand Resource's revenue meter, in which the Demand Reduction Value is based on the output of the generation asset. Distributed generation resources are considered "behind-the-meter" generators, such as combined heat and power (CHP) systems, wind turbines, and photovoltaic generators that generate electricity on site.

The DRACS simulator uses baseline values and estimates of the dispatched load or available ancillary service to provide statistical confidence levels for the DRMS system to go forward with the implementation of the control decisions.

2.6.2.1. Simulator Components

The simulator sub-modules are shown in Figure 9: Operational Flow in Simulator . In addition to those sub-modules, there are support components that ingest or convert between data representations to support the operations of other sub-modules. We list those as well – a complete list of sub-modules in each of its two modes of operation is as follows:

1. Offline analysis mode
 - a. Input parameter ingest engine
 - b. Topology mapping module
 - c. Power flow solver

- d. Alternatives exploration module
 - e. Statistical estimator for dispatched load
2. Run-time scenario analyzer module
- a. Database connectors to customer database
 - b. SCADA/Historian interface
 - c. Scenario ingest module
 - d. Dispatch prioritization module
 - e. Power flow solver
 - f. Contingency prioritization module
 - g. Human-user alternatives proposer and visualization interface
 - h. Tracking module for dynamic state-estimation
 - i. Dispatch performance tracker

2.6.3. Simulation Framework Findings

- Gaps exist in the simulation technology space to understand communications impacts on power system behavior.
Most simulation environments either focus only on the power system or only on the communication network. We find that that the DRACS functionality needs an integrated simulation of the communication network (digital) and the power system network (analog). The integrated approach alone can correctly relate the delays in the message with the control timing latencies.
- Human behavior aggregation will need to be specified (at ISO and at Load Aggregation Point level).
The simulation for expected dispatch requires statistical means to gain confidence in the outcomes. Aggregation granularity is a key requirement to be able to allow for variability in human behavior. For instance, a sub-division or metropolitan area aggregation has a focused dispatch strategy. On the other hand a dispersed strategy needs a hierarchical aggregation structure with confidence limits computed at each layer of the hierarchy.
- Dispatch request hierarchy from ISO to IOU needs clarification as a module in DRMS.
The location of operation of a DRACS system affects where in the distribution hierarchy dispatch decisions must be made. The CAISO may obtain high-level needs from the simulation to request dispatch (e.g., for peak shaving). These will need to be translated to requests to IOU's that can make their individual decisions on the precise dispatch approach. DRACS operating in the CAISO context simulates the state space at a different granularity than if it were operating within a utility. Emerging proposals for proxy and dynamic demand response resources further diversify the mode of obtaining system relief through demand response.

- Statistical aggregation approach are effective but estimates (for operators) will need to be validated with monitoring signals during operation
There are emerging recommendations to monitor the system for Demand Resources status. With statistical estimation, although the appropriate levels of confidence limits may be achieved, the reliability of the power system will require sampling of the set of demand resources. Thus there is an aggregation of the probabilistic estimate of dispatch, and an estimate of the actual system status by sampling. More pervasive sampling, possibly integrated with emerging metering infrastructures will fill any confidence gaps. The confidence gaps in the interim must be maintained within the margin of tolerance for reliability.
- Delay vs. Control tradeoff differs for different technology mix for dispatch. Integrating technology alternatives in one bag for dispatch will need a lot of simulation to get confidence.
Current simulations abstract load behavior. These will need to be refined according to the technologies dispatched. The delays in obtaining the response (to, e.g., Time-Of-Day pricing related thermostat settings vs. critical peak price signals) affect the stability of the system. The dispatch strategy must simulate the response time based on the technology dispatched.

2.6.4. Simulator Framework Case-Study Example

Controllable load can in part replace generation for frequency regulation and spinning reserve. How this is done depends on the time scales available for control. Control of frequency in an emergency, to prevent under frequency failures for example, requires action in seconds to minutes. Load acting as spinning reserve has minutes to act. The potential for dynamic control can be understood with a very simple model, which we evaluate by simulation of a detailed model of a centralized control process operating on the IEEE 118 bus test system. The details of this case-study may be found in the results of Task 4 (see Section 1.2.4).

This scenario uses the IEEE 118 bus test case. There are 34 generators, each modeled with uniform dynamic parameters. To emphasize the role of the load control in damping frequency oscillations, the control parameters of the generators are set to give the system an under-damped response to a step change in load. For this experiment, there is a 30% reduction in the electrical load at $t=1$ second. Figure 10 (a) shows the response of the 34 generating units when active load control is not used; the under-damped response is obvious in the large, initial swings between 61 and 58.5 Hertz. Figure 10 (b) shows the improved response for the same experiment but with active control of the loads; superimposed on the frequency plot is the load reduction effected by the control center. In this case, the control center is notified of every 0.2 Hz change in frequency at the terminals of the generators. These measurements arrive via the communication network, and, upon receipt, the control center uses the average value of its frequency measurements to determine the quantity of demand-responsive load to be dispatched (shed). The adjusted load level is then transmitted to the load busses via the communication network, each bus acting on the request when it is received.

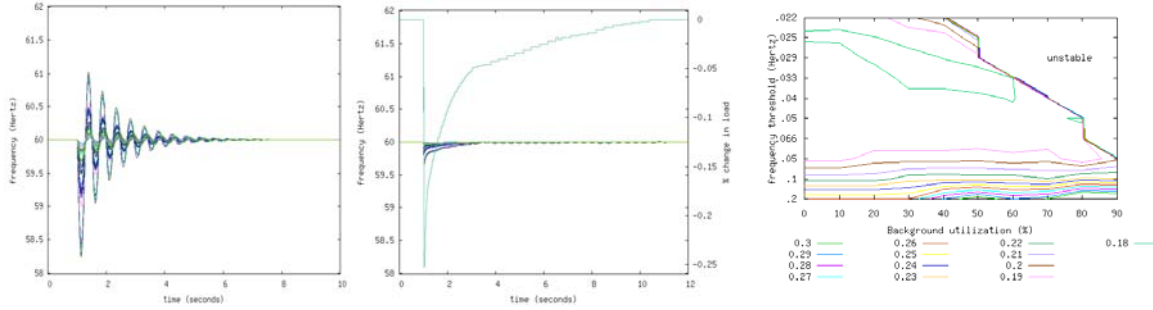


Figure 10: (a) No Active Control (left); (b) Active Control (middle); (c) Stability Region (right)

To compare scenarios with different network parameters, the performance of the controller is measured by the integral of the square of the frequency excursion over the duration of the experiment. Figure 10 (c) shows the performance of the system as a function of Δf and the background utilization of the network. Two facts are immediately apparent. First, the performance generally improves as the sensor threshold becomes smaller, but there are diminishing returns past $\Delta f = 0.05$ Hertz. Second, a greater portion of the network's capacity must be held in reserve to ensure that the contingency, a 30% loss of load in this case, does not overwhelm the network. If this occurs, the generators may stabilize the system before the load adjustments are delivered to the load actuators. This delayed control signal then becomes a contingency itself, generating more control data, and further aggravating the problem. This simple study shows that there is a tradeoff to be made between the efficacy of the DRACS simulator-driven dispatch scheme (as determined by its sensor transmit threshold) and amount of network capacity require to support it. Moreover, using this simple model of the communication network, there appears to be a minimum capacity required to ensure the control actions do not themselves instigate a destabilizing dynamic. Simulations of this kind are invaluable for examining C3I (command, control, communication, and information) induced dependencies in distributed control systems, and this case study illustrates the nature of the calculations performed by the DRACS simulation framework.

2.7. Standards Gaps

One of the disturbing findings for the DRACS project was identifying the lack of comprehensive standards to support DR interoperability. A common pricing model needs to exist across all the various Smart Grid domains (Markets, Operations, Service Provider, Bulk Generation, Transmission, Distribution, and Customer), making real time wholesale and/or retail pricing available to all domains. IEC 61970, IEC 61968 Common Information Model (CIM), and IEC 61850-7-420 do not fully support common frameworks for treating demand resources, but could be modified to support that need. The OpenADR specification is not a standard, but has a strong data model for DR and parts of the whole should be vetted and rigorously addressed to evaluate against DR standards semantics requirements. IEC 61968's CIM is missing many of the semantic pieces for communicating with DERs and Demand Resources, and may be able to incorporate work done with the OpenADR data model.

2.8. Human Behavior and Plug-n-Play

Human behavior is the most unpredictable aspect of DR event scenario generation. It will take time for models of human behavior and anticipated reaction to DR events to mature. A statistical representation will need to be incorporated and refined over time (due to changing economic and social environment conditions) in a realistic DRMS. The DRMS and its operator will need to be nimble, observing grid activities and DR responses, and be prepared to “fine tune” DR signals and commands until the grid conditions meet acceptable tolerance levels.

Another aspect of human behavior here that influences these systems is the current inclinations in society and demographics (as different from consumption patterns which utilities handle well). Factors such as peer pressure and vaguely defined social responsiveness are likely to be enablers of DR adoption, and the potential rush of DERs and Demand Resources into the American home will probably have a much more dramatic effect on the level of DR event support than anticipated – especially once DERs and Demand Resources are available in retail stores as plug-n-play consumer devices, and they automatically respond to event signals with little or no human interaction.

Plug-n-play interoperability will be a necessity once DERs and Demand Resources become purchases consumers can make easily. How this will be done, whether the devices will auto-register themselves in some “global device registry”, or whether the utility/ISO even needs to be aware of a particular device’s presence on the grid has not been decided. It is not even clear where the lines of demarcation between the consumer and the grid are. At what point does the consumer electronics industry assume control and the electric power industry relinquish control to the consumer? Does it end at the meter or premise gateway? Or, can the utility/service provider/ISO enter the customer premise and talk directly to the devices? Or, is there some hybrid solution where some devices are directly controlled by an outside entity or service provider, but others are managed only by the consumer himself? It is a challenge that is certainly solvable, but it has profound implications for how DRACS and the DRMS manage DERs and Demand Resources (and how many).

3.0 Summary, Conclusions, and Recommendations

In comparing a utility operation with military mission, military organizational requirements call for tight coordination of multiple command structures controlling individual resources and assets integrated in a coordinated action to achieve an objective in support of a mission. Similarity with a utility organization is the multiplicity of individual resources and assets controlled by individual departments. Unlike military organizations, a utility's mission is singular (lowest cost electricity at highest reliability) and non-changing although objectives are evolving and changing with the advent of new Smart Grid technologies such as

- integration of distributed generation especially renewables
- implementation of smart metering
- providing customer access to energy usage
- integration of advanced grid control devices
- integration of demand response resources
- serving plug-in electric vehicles (PEVs)

What constitutes C³I in the military directly maps to C²I in the utility world dropping "Command" functionality which is not applicable. This project has developed a Control Communication and Information (C²I) system architecture that provides utilities the ability to identify, organize, analyze, forecast and execute demand response resources.

Classical military C³I systems have evolved that integrate real time data sources with behavior analysis and decision making toolsets. This capability is just now appearing in the utility industry. With real time up-to-date information available from all customers and across distribution grid and distributed resources, utilities can now use C²I methodologies to develop operational strategies that are built upon high performance computational platforms.

The findings identified in the previous sections lead to the conclusion that further research is needed around DRACS and the DRMS. Demand Response is still quite immature. This is evident in the various different ways that the California utility companies are approaching Demand Response deployments. Like many other Smart Grid technologies, California is out in the lead with Demand Response technologies. There is obviously risk associated with being the early adopter and trailblazer, but also opportunities to lead the industry, set a precedent, and help find solutions that not only work well in California, but also in the rest of the US and beyond. This risk can be mitigated by using layered software technology and loose coupling, ensuring firmware is remote-upgradeable, and by objectively reviewing the DR landscape, standards development requirements and timelines, regulatory and policy inertia, and consumer products plans around Demand Resources and DERs. In fact, a comprehensive risk analysis may suggest that California closely track NIST Interoperability

Standards adoption. Nevertheless, there are unique regulatory demands and critical peak power conditions experienced by California grid participants that require aggressive action. There is a critical need to perform additional technology, policy, risk, security, process, and peer analyses before DR strategies and systems are committed. California should invest in these types of studies and work to ensure that the large IOU utilities' DR systems can interoperate with each other and the CAISO for the overall benefit of the utilities and grid partners, and consumers.

3.1. DRACS Follow-on Recommendations

Research is needed in the following areas that will result in technologies that are embodied in C²I offerings:

- Development of a full prototype simulator for creating and evaluating DR scenarios
- Automatic device registry mechanism for demand resources
- Demand Resource behavior models for each customer class and device class
- Input into industry groups such as Open Smart Grid AMI Enterprise Working Group. (See AMI Ent Use Cases 1.0
<http://osgug.ucaiug.org/utilityami/AMIENT/Shared%20Documents/Forms/AllItems.aspx?RootFolder=%2futilityami%2fAMIENT%2fShared%20Documents%2fUse%20Cases&FolderCTID=%7bAE210767%2d1957%2d42A0%2dA6B4%2d46E383ED6114%7d>)
- Support industry standardization of Demand Response business processes at NAESB. (See NAESB Demand Side Management and Energy Efficiency Working Group
<http://www.naesb.org/dsm-ee.asp>)

3.2. DRMS Research Recommendations

3.2.1. DRMS Module Elaboration

There are many questions to answer about what the optimal DRMS system should look like, the modules necessary, requirements and reference architecture for each module, the internal and external interfaces, and the system information flow. Is it a separate Enterprise system? Is it multiple systems? Or, is it part of the Distribution Management System (DMS)?

The EnerNex team needed a mid-level understanding of the overall DRMS system in order to properly carve out and address the requirements and reference architecture for DRACS. We spent the first two months of the DRACS project working internally and then with SDGE and Lockheed Martin system engineers to establish and agree upon the DRACS/DRMS relationship discussed in section 2.1.3. The result of this collaborative effort was the identification of seven (7) primary modules and a high level functional description of each.

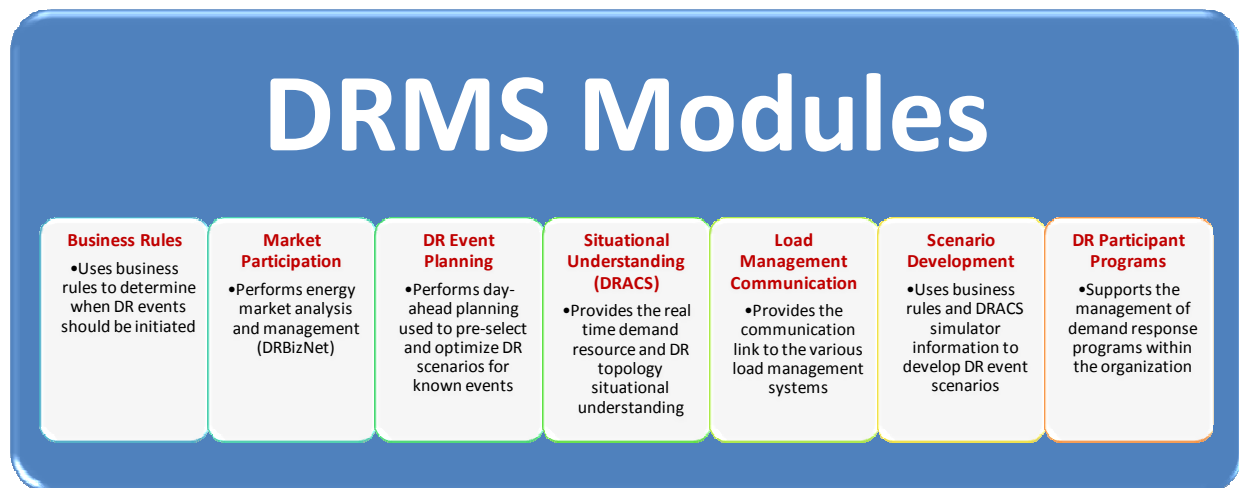


Figure 11: There are 7 primary DRMS modules

Several of these modules could use additional research similar to that performed with the DRACS module. The business rules, market participation, DR event planning, scenario development, and DR participant programs modules are non-trivial. The load management communication module is straight-forward and is shown in the following section.

3.2.2. Pilot Existing Load Management Technologies

Efforts are underway and need to be expanded to pilot existing load management technologies. Use of pilot DR programs help to examine gaps in technology, methodologies and deployment and help build industry knowledge on the readiness of DRMS. Most Demand Response implementations have not been performed from a DRMS viewpoint, but are a collection of independent programs with specific criteria and objectives.

An example is the AutoDR system developed by Lawrence Berkeley National Lab's (LBNL) This Demand Response protocol and data model invention has been designed for commercial and industrial customers to link facility energy management control systems (EMCS) with the utility. To the DRMS, AutoDR looks like another load management system, which can be managed in conjunction with other load management systems at a higher, macro demand resource management strategy level. Since AutoDR has already been implemented and more implementations are imminent, it would be helpful to California utilities, aggregators, and C&I customers to develop a strategy, roadmap, and implementation guide for AutoDR inclusion in the DRMS suite of managed demand resources.

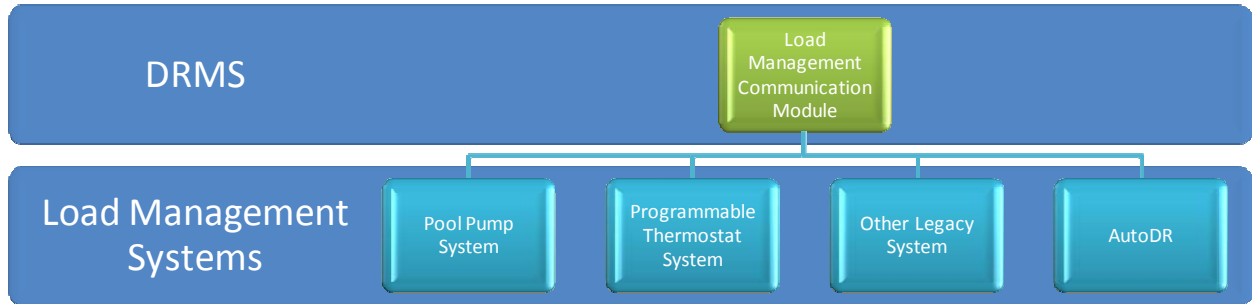


Figure 12: AutoDR systems may be managed as a Load Management System within DRMS

The following are a list of general requirements that need to be assessed as part of any DRACS implementation

- Demand Response technology readiness and risk analysis
- Regulatory needs to support Demand Response implementations
- Connectivity to NIST Smart Grid interoperability standards development effort

In general, over the course of conducting this project, awareness has steadily grown in the utility industry of the pressing need to develop and implement Demand Response Management Systems (DRMS) and a Demand Response Analysis and Controls (DRACS) system as part of a comprehensive C²I strategy that addresses all Demand Response programs, resources and operational components.