BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

Order Instituting Rulemaking to Integrate and Refine Procurement Policies and Consider Long-Term Procurement Plans.	Rulemaking 12-03-014 (Filed March 22, 2012)

COMMENTS OF ENERNOC, INC. ON WORKSHOP TOPICS IDENTIFIED IN ALJ'S RULING OF SEPTEMBER 14, 2012

Sara Steck Myers
Attorney for **EnerNOC, Inc.**
122 - 28th Avenue
San Francisco, CA 94121
Telephone: 415-387-1904
Facsimile: 415-387-4708
Email: ssmyers@att.net

Mona Tierney-Lloyd
Director, Western Regulatory Affairs
EnerNOC, Inc.
P.O. Box 378
Cayucos, CA 93430
Telephone: (805) 995-1618
Facsimile: (805) 995-1678
E-mail: mtierney-lloyd@enernoc.com

October 9, 2012

BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

Order Instituting Rulemaking to Integrate and Refine Procurement Policies and Consider Long-Term Procurement Plans.	Rulemaking 12-03-014 (Filed March 22, 2012)

COMMENTS OF ENERNOC, INC. ON WORKSHOP TOPICS IDENTIFIED IN ALJ'S RULING OF SEPTEMBER 14, 2012

EnerNOC, Inc. (EnerNOC) respectfully submits these Comments on the Workshop Topics identified in the Administrative Law Judge's (ALJ's) Ruling issued in this proceeding on September 14, 2012 (September 14 ALJ's Ruling). These Comments are filed and served pursuant to the Commission's Rules of Practice and Procedure, the September 14 ALJ's Ruling, and the ALJ's Ruling issued by electronic mail to the service list on October 4, 2012, extending the time to file these Comments to October 9, 2012.

I. INTRODUCTION

On September 7, 2012, the Commission held a joint Workshop in this proceeding (R.12-03-014 (Long Term Procurement Plans (LTPP)) and R.10-12-007 (Energy Storage) (September 7 Workshop). EnerNOC actively participated and made a presentation at the September 7 Workshop, which is attached hereto as Appendix A.[1]

EnerNOC also testified and participated in the Local Reliability Track 1 evidentiary hearings, which concluded in August 2012, and has since filed its Opening Brief on September 24, 2012, with a Reply Brief to follow on October 12, 2012. According to the September 14 ALJ's Ruling, however, comments and reply comments in response to Workshop Topics identified by that ruling "maybe used to inform either Track 1 or Track 2 (or both Tracks)."[2]

[1] Presentation of EnerNOC, Inc., at September 7 Workshop (Appendix A hereto).
[2] September 14 ALJ's Ruling, at p. 1.

Yet, some of the topics identified have been addressed in Track 1 testimony and briefs. In addition, some of the issues identified in the September 14 ALJ Ruling may be the subject of future consideration in R.11-10-023 (Resource Adequacy).

Unfortunately, the September 14 ALJ's Ruling does not indicate how the evidentiary record or briefs in Track 1 will be affected by the September 7 Workshop and comment process or vice versa. Without that clarification, EnerNOC's participation in the September 7 Workshop and its comments herein are intended to be supplemental to, not in replacement of, its testimony and positions offered in the Track 1 hearings and briefs.

With that qualification, EnerNOC offers the following recommendations on the topics identified in the September 14 ALJ's Ruling, as discussed in further detail herein. Namely, EnerNOC recommends that the Commission do the following:

1. Reduce the total need amount determined by the CAISO in its once-through-cooling (OTC) study by the expected growth in preferred resources over the planning period. Recognize that over 1,200 MW of existing, dispatchable DR capacity exists in both the LA Basin and the Big Creek/Ventura LCAs that could reduce the local need. Develop DR resources during the period that fossil generation resources are being built.
2. Define flexible attributes or characteristics and the need for these types of resources.
3. Define how preferred resources can participate in providing those flexible services.
4. Authorize an RFO for the "net" short position, considering growth in preferred resources, with the flexible attributes defined and participation by preferred resources in supplying those flexible attributes defined. Alternatively, direct the investor-owned utilities to set aside a percentage of the total net local resource need for preferred resources.
5. Determine the means for evaluating bids, including bids from preferred resources.

II.
RESPONSES TO WORKSHOP TOPICS

EnerNOC offers the following responses to the Workshop Topics posed by the September 14 ALJ's Ruling. The topics are recited (using the same numbering as the ruling), followed by EnerNOC's response.

1. What changes should be made to the rules governing the Investor-owned Utilities (IOUs') procurement process that would allow all resources (natural gas combined cycle, combustion turbine, storage, demand response, combined heat and power, renewable, etc.) to compete fairly in meeting identified needs? Please provide specific proposals for structuring an all-source procurement process.

In the Local Reliability Track 1 evidentiary hearings, EnerNOC witness Tierney-Lloyd testified that an all-source request for offer (RFO) for preferred resources alongside conventional resources may not be the best way to proceed, "unless there is a very clear understanding of the products that will be solicited."[3] This position was reiterated by Ms. Tierney-Lloyd in EnerNOC's presentation at the September 7 Workshop (attached as Appendix A and incorporated herein).

In this regard, this LTPP rulemaking will determine what local and system capacity will be needed through 2021. What will not be clear in this proceeding is what kind of flexible capacity resource is needed, by when, and how much. That discussion will be addressed in R.11-10-023 (RA).

Therefore, if the Commission is interested only in filling those local and system capacity needs, then the Commission can instruct the investor-owned utilities (IOUs) to issue RFOs for that purpose. As Ms. Tierney-Lloyd testified in Track 1: "Local uncommitted EE (energy efficiency) and DR (demand response) could reduce the need…within the local area."[4] The fact is that DR capacity resources in the Pennsylvania-New Jersey-Maryland (PJM) regional

[3] Local Reliability Track 1(Track 1) Exhibit (Ex.) EnerNOC-3, at p. III-9 (EnerNOC (Tierney-Lloyd)).
[4] Id., at p. III-4 (EnerNOC (Tierney-Lloyd)).

transmission organization (RTO), which comprise almost 10% of total capacity resources in that system, can be called for system or local purposes. In ISO-Northeast (NE), DR capacity resources can be called for system, zonal, or sub-zonal purposes. Therefore, there is no reason why DR resources in California cannot be used to meet local capacity needs if DR resources can be used for local capacity purposes in other markets. In addition, in its Track 1 testimony, EnerNOC identified several fast response services provided by DR resources in other markets. There is no reason why DR resources cannot provide comparable services in California.

However, CAISO has made it clear that it is not capacity alone that is being sought; it is capacity with certain flexible characteristics or attributes for purposes of balancing renewable intermittency. The problem is that this Commission has not yet defined, or adopted definitions, for those flexible characteristics or attributes. So, resource providers, including and especially those providing preferred resources, cannot bid to provide a resource characteristic that has not yet been defined.

EnerNOC's testimony in Track 1 of this proceeding has demonstrated that DR resources can provide some of the flexible attributes that the CAISO is seeking.[5] At a minimum, the issues that are pending resolution in the R11-10-023 (RA) must be resolved so that resource acquisition can incorporate those flexible resource characteristics, including those provided by DR resources. Without understanding exactly how much capacity is needed that is capable of providing flexible characteristics and the definition of those characteristics, a resource solicitation process will contain too much uncertainty and result in discretionary resource selection, which may not achieve Commission policy goals for the Loading Order.

There are temporal differences in the lead time necessary to develop a fossil-fueled plant, approximately seven (7) years, and other resources, such as demand response. DR does not

[5] Track 1 Ex. EnerNOC-2 (EnerNOC (Hoffman)).

require a seven-year lead time in order to have an operational resource in place. For this reason, it may not make sense to issue an RFO today for a demand resource that will not be needed until 2017, 2018, or 2019. Too many things could change relative to the marketplace (rates, customer availability, value of the service, role of the utility) that would introduce a significant amount of risk to the DR bidder over that period of time that would not be known and could not be effectively hedged if bids were required today. However, those DR resources can be developed over the period of time that fossil generation resources are being built. DR resource development and capability is likely to occur as a result of smart grid deployment as well as in response to the need for flexible capacity resources for renewable integration purposes.

EnerNOC recommends that the Commission adjust the "need" for fossil resources by the expected growth in preferred resources over the planning horizon and, during the period leading up to the point where resource need is likely to occur, develop those preferred resources in the interim period when the fossil-fueled plants are being permitted and built.[6] This step would be followed by determining the need for and the definition of flexible capacity resources, how preferred resources may participate in the procurement of flexible resources, and how bids will be evaluated. If, however, the Commission decides to move forward with an all-source RFO, EnerNOC recommends that a certain percentage of the "net" need in the LCA be reserved for preferred resources to bid.

In terms of rule changes that are needed and can be adopted now to permit DR resources to participate in an all-source RFO, EnerNOC recommends that the Commission take the following action:

[6] See, e.g., EnerNOC Track 1 Opening Brief, at pp. 1-3.

- ***Define Flexible Capacity Resources and the Resources that are Eligible to Provide Those Products*.**

  As mentioned above, if capacity resources are to have flexible attributes, the definition of those attributes would need to be adopted by the Commission so that all parties have the same understanding of the product. EnerNOC's Track 1 testimony and September 7 Workshop presentation have made clear that DR does not have to provide energy 365 days per year and 24 hours per day to provide value to the local area or the system. The fact that DR can change the load shape such that additional resources, generally during peak periods, are not required can provide savings to all customers. That benefit, of clipping the peaks, can be translated to other times of the year or within the day. However, if the resource must be dispatchable on a basis comparable to a base-load resource or generator, then the likelihood that DR resources will be chosen to provide a service will be reduced or eliminated. The availability and dispatchability of DR should be determined so as to minimize the need to build incremental generation for that peak resource requirement.

- ***Define Demand Response as Capable of Meeting Local and System Needs*.**

  In response to any suggestion that DR cannot meet or reduce local reliability needs based upon the fact that DR resources have not been required to do so up until this point in California, it has been EnerNOC's experience, in the markets in which it participates, that DR resources *can and do* provide local reliability and are *not* used solely as system resources. This is true in the organized markets in which EnerNOC participates. Further, the Commission has required local deliverability, by local capacity area (LCA), in order for DR resources to qualify for local resource adequacy (RA). As such, both Pacific Gas and Electric Company (PG&E) (A.12-09-004) and Southern California Edison Company (SCE) (A.12-09-007) recently concluded RFO processes for DR resources in which they sought, and received, DR resources that are capable of being dispatched on a local basis.

- ***Define how DR Qualifies as a Capacity Resource, Including DR Participation in the Wholesale Market.***

  It is critical to make clear that DR counts as a capacity resource when it is a dispatchable resource, whether that resource is provided under contract to the utility or participating directly in the wholesale market. In turn, the purchasing load-serving entity can count that DR capacity against its RA requirement.

- ***Cost-Effectiveness Calculations Must Value the Benefit that DR Resources Provide.*** The current cost-effectiveness methodology for DR resources looks at DR solely as a peak-shaving resource in the summer months for a total of 250 hours of availability. It does not value locational dispatch, quick response, availability outside of the summer months, the provision of ancillary services, or any other flexible attribute that may be adopted.

- ***The Future Market Structure for DR resources is in Flux.*** It is unclear at this juncture as to whether DR resources will continue to be developed in response to IOU-issued RFOs or through participation directly in the wholesale market. How this issue is resolved will directly affect DR resource development in the future. In recent decisions, within the past two years, the Commission has resisted authorizing the IOUs to issue new RFOs for DR resources, even for a short-term (1-2 years). However, the Commission is likely to encourage the utilities to enter into long-term contracts with generators for purposes of meeting the LCR. The Commission should not discourage long-term DR contracts as a result of this process and should create comparable contracting opportunities for preferred resources, including DR, as it is contemplating for fossil resources. EnerNOC supports long-term contracting authority for DR resources, especially since participation in the wholesale market is uncertain.

2. **What amendments, if any, would be necessary to the most recent long-term Request for Offers issued by Pacific Gas and Electric Company (PG&E), San Diego Gas & Electric (SDG&E), and Southern California Edison (SCE) to ensure that all resources are eligible to compete in meeting future Request for Offers (RFO)? Are there any changes specific to meeting Local Capacity Requirements (LCR)?**

EnerNOC reserves the right to respond to this question further in reply comments. However, EnerNOC has just responded to the RFOs for DR resources issued by both PG&E and SCE for 2013 and 2014. EnerNOC has been selected to provide DR services to both IOUs, which is locally dispatchable and some of which is responsive within 30 minutes, pending Commission approval.

3. What specific characteristics or attributes must any resource -- including demand-side, energy storage, or distributed -- provide in order to meet future procurement needs? In the absence of a Net Qualifying Capacity, what methodology should be used to determine a proxy capacity value for resources lacking a Net Qualifying Capacity for use in LCR capacity accounting? How can these characteristics or criteria be turned into criteria to evaluate resources bid into a Request for Offers to meet LCR or other needs? How should those criteria be weighted?

First, if a resource is intended to meet local or system capacity needs, the resources should be capable of being dispatched within the area they have been designated to meet those requirements. Currently, for meeting RA requirements, DR must be available to be dispatched up to 24 hours per month. For 2013, there is no limit on the amount of DR resources that can meet the RA requirement.[7] In order to meet the local RA requirement, the DR resources must be locally dispatchable.[8]

Further, in the guides and resources developed by Energy Division to determine the amount of local capacity associated with DR programs for 2013, in the summer months over 1,000 MW of event-based DR capacity is located within the LA Basin and over 200 MW of capacity is located in the Big Creek/Ventura local capacity area (LCA).[9] None of this capacity was counted against the need determined by the CAISO in its once-through-cooling (OTC) analysis. Net qualifying capacity for DR resources is determined using load impact protocols.

If other criterion is to be used, such as flexible characteristics, that criteria must be defined and adopted by the Commission before it is used as a basis for issuing an RFO. In order to evaluate resource bids objectively, all parties must have a universal understanding as to the definitions of flexible capacity.

---

[7] 2013 Final RA Filing Guide, at pp. 12-14.
[8] D.11-10-003, Ordering Paragraph 1.a., at p. 34.
[9] See: CPUC Energy Division, 2013 Total IOU DR Program Totals by Program and Local Area Grossed Up for T&D Losses, SCE Program Totals , attached and incorporated herein as Appendix B.

4. What are the pros and cons of the following procurement methods with regard to: 1) local procurement considered in Track 1 of LTPP, and 2) operational flexibility and general system procurement considered in Track 2 of LTPP?

A. Continuation of current practices for procurement with minor clarifications;

If by "continuation of current practices for procurement" the Commission means that procurement would consist solely or primarily of fossil generation to meet the local procurement requirement in Track 1 of the LTPP, as suggested by the CAISO, PG&E, and San Diego Gas and Electric Company (SDG&E) in their testimony, then, that approach discriminates against preferred resources, is inconsistent with the Commission's Loading Order, and may displace the need for development of preferred resources in the future. EnerNOC would see that approach as a "con." Further, if the Commission adopted SCE's proposal in Track 1 to give SCE unlimited discretion to determine internally the mix of resources it determines would meet its resource need, including consideration of preferred resources, and provide its results to this Commission, then, again, EnerNOC would also consider this approach a "con."

Unfortunately, it appears as though the IOUs need to be reminded again and again that the Loading Order is not simply a suggestion, but a *requirement* to first seek all cost-effective, reliable and feasible energy efficiency and demand response, then renewable and distributed resources. However, only the Commission can enforce this rule in order to make preferred resources a reality.

It is EnerNOC's recommendation, therefore, that the Commission reduce the LCR need calculated by the CAISO for SCE's local capacity areas (LCAs) by the amount of existing and future DR and EE resources that can be dispatched within the LCA, then include the likely amount of renewable, CHP and distributed resources; define the need for and characteristics of flexible capacity resources; define the manner in which preferred resources can participate in the RFO; and only then authorize the IOUs to issue an RFO for the net capacity for the LCA.

Otherwise, the Commission should set aside a percentage of the LCR to be met by preferred resources.

In the interim, the Commission, the IOUs, and the stakeholders should be working toward development of preferred resources. The Commission must take into account the temporal differences that exist between resource types in terms of the time necessary to develop the resource. Certain resources can be developed between now and when the CAISO has determined that a resource need exists so as to reduce that need in the future period, whereas fossil generation resources need to begin the selection process earlier because they require a much longer lead time to develop.

B. A "portfolio approach" that allocates, based on strategic/portfolio considerations, the total quantity of new flexible resources among various eligible resources (for example, how could/should the allocations be adjusted periodically based on current or expected conditions?).

a. SCE provided two proposed alternatives to filling any LCR need at the September 7, 2012 workshop, one with flexibility for SCE in procuring resources via two separate tracks, and another approach using an all-source RFO. Is there some way to blend these approaches? If so, how, and should the Commission attempt to do so?

SCE proposed two alternative processes for resource selection to meet an identified LCR need. The first was through a two-track selection process, and the second was through an all-source RFO.

EnerNOC has concerns with both processes. As it relates to the two-track selection process, SCE proposed to have large-scale resources either go through an AB 1576 process or through a solicitation process, while non-large scale resources would be internally assessed and evaluated for their economics, viability, or future potential. That evaluation appears to be completely internal to SCE. It is not clear what criteria SCE would use in its assessment. Yet, the results of the large scale and the non-large scale processes would be feed into a least-cost/best fit solution that SCE would adopt.

As EnerNOC testified in Track 1 and reiterated at the September 7 Workshop, EnerNOC does not think that DR resources are going to totally eliminate any need for any other resource in the LA Basin nor does EnerNOC believe that DR resources are going to have the same level of dispatchability or availability as a generator. *However*, DR *can reduce and meet* a portion of the LCR by reducing the need for building capacity for the last MW of need. In that instance, DR would provide the service so that generation would not have to be oversized and sit idle for most hours of the year except for that peak period.

Likewise, if SCE's RFO construct includes selection criteria for all resources to provide "continuous hours of operation," DR is going to be disqualified from the start. That is not the nature of DR resource services. SCE uses words like ramping and load following, which have not been applied by the Commission to DR resources. In her presentation at the September 7 Workshop, Ms. Tierney-Lloyd confirmed that those definitions were not developed with DR resources in mind. They were developed for generators.

Therefore, SCE's all-source RFO approach contains the very elements that EnerNOC would caution against if the Commission sincerely wants to include and encourage all resource types, especially preferred resources, in meeting local or system resource needs. SCE's two-track process for its internal evaluation raises many of the same questions as to how SCE would evaluate, and eliminate, certain resources from further consideration. Finally, preferred resources should not be exclusively evaluated on a least-cost basis because there are inherent "benefits" to being a preferred resource that may not be captured in the price of electricity or natural gas generation today.[10]

C. Establishing a set of minimum criteria for operational flexibility characteristics for all acquired resources;

EnerNOC suggests that the Commission establish minimum criteria for operational flexibility characteristics for each resource. The criteria should not be the same for all resources because different resources will have different capabilities.

In this regard, DR qualifies as a system capacity resource for purposes of meeting summer peak demand with criteria that is specific to DR resources. Similarly, renewable resources have specific criteria, as use-limited resources, that determine how to calculate the amount of capacity that counts toward resource adequacy. Then, so long as the resource meets the minimum operational flexibility characteristics criteria established for it, and the resource is locally dispatchable if it is considered to meet the LCR, the resource is an eligible resource to bid in an RFO process. Preferred resources should not be eliminated from contributing toward, reducing, or meeting flexible resource characteristics just because they have certain use limitations.

D. A "strong showing" requirement that the utility must demonstrate that its procurement process was substantially open to all resource types and appropriately considered all of the values discussed above and that the resulting portfolio of resources is an optimal solution.

EnerNOC objects to an "after-the-fact" demonstration by the utility to support why it did not choose certain resources and prefers that the Commission provide guidance to the IOUs *in advance* of procurement decisions being made. As stated above and in EnerNOC's Track 1

[10] See, R.09-11-014 (Energy Efficiency) EnerNOC Comments on Demand Side Cost-Effectiveness Issues (October 1, 2012), at p. 5.

testimony,[11] there are ways to eliminate certain resources from consideration. If, for example, SCE requires continuous hours of operation for DR resources to be 8,760 hours per year, then no DR resource is going to meet that requirement.

Thus, having utilities inform the Commission or the stakeholders of the selection criteria *after* the selection has already been made does not assist further transparency as to what criteria a resource needs to meet or why it has been or was at risk for being eliminated. In addition, if the Commission later invalidates the selection process or criteria, then SCE, its ratepayers, and many stakeholders would have wasted a lot of time and money. Definition in advance of a selection process will reduce conflict and controversy over resource selection decisions where discretionary selection criteria would eliminate certain resource consideration.

E. Adjusting existing procurement mechanisms, such as the Renewable Auction Mechanism, to focus on the physical locations with needs that can be met by that programmatic resource.

EnerNOC reserves the right to respond in reply.

5. At the September 7th workshop, some parties discussed retrofits to existing generation assets as a potential source of incremental capacity. What, if any, changes would need to be made to the most recent long term RFO issued by PG&E, SDG&E, and SCE to allow for incremental capacity associated with retrofits to existing generation to compete to meet Local Capacity Requirements? Are there any differences in payment streams that should be given for existing capacity, as opposed to upgraded capacity?

EnerNOC reserves the right to respond in reply comments.

[11] Track 1 Ex. EnerNOC-3, at pp. III-9 and III-10 (EnerNOC (Tierney-Lloyd)).

6. At the September 7th workshop, both SCE and Enernoc raised concerns that it would be difficult to procure demand response resources that match the online dates (2017 to 2020) and duration (e.g., 20 years) of the conventional generation that is being contemplated as a source of LCR capacity. How could a demand side program be authorized through this LCR procurement process that delivers an on-line date and a duration that is comparable to conventional generation? What additional values are currently attributed to demand response resources in other markets that are currently not accounted for in California, and that might be taken into account as part of an LCR procurement process?

As EnerNOC has made clear here and in its Track 1 testimony and brief, one way to address the need to "incorporate" preferred resources is to reduce the need that would be available to be filled by conventional resources by expected growth in preferred resources in the LCA through 2021.[12] In the interim, preferred resource programs can be developed so as to reduce the need in the LCA or to meet the need as the need for and definition of products becomes clearer. The Commission should develop definitions for flexible capacity characteristics and determine how each resource, including demand response resources, would contribute toward meeting those characteristics.

Alternatively, in an all-source RFO, the Commission should define a percentage that will be set aside for fulfillment by preferred resources, including DR resources. As discussed above, other markets recognize demand resources as comparable capacity resources for either system or local capacity needs as generation.

III.
CONCLUSION

EnerNOC appreciates the opportunity to provide these comments and respectfully requests that the Commission take the following actions:

1. Reduce the total need amount determined by the CAISO in its once-through-cooling (OTC) study by the growth in preferred resources over the planning period. Recognize that over 1,200 MW of existing, dispatchable DR capacity exists in both the LA Basin and the Big

[12] Track 1 EnerNOC Opening Brief, at pp. 15-20; Ex. EnerNOC-3 at pp. III-8 and III-9 (EnerNOC (Tierney-Lloyd)).

Creek/Ventura local capacity areas that could reduce the local need. Develop DR resources over the period where fossil generation resources are being built.

2. Define flexible attributes or characteristics and the need for these types of resources.

3. Define how preferred resources can participate in providing those flexible services.

4. Authorize an RFO for the "net" short position, considering growth in preferred resources, with the flexible attributes defined and participation by preferred resources in supplying those flexible attributes defined. Alternatively, direct the investor-owned utilities to set aside a percentage of the total net local resource need for an RFO for preferred resources.

5. Determine the means for evaluating bids, including bids from preferred resources.

Respectfully submitted,

October 9, 2012

/s/ SARA STECK MYERS
Sara Steck Myers
For EnerNOC, Inc.

Sara Steck Myers
Attorney at Law
122 - 28th Avenue
San Francisco, CA 94121
Telephone: 415-387-1904
Facsimile: 415-387-4708
Email: ssmyers@att.net

And

Mona Tierney-Lloyd
Director of Regulatory Affairs
EnerNOC, Inc.
P. O. Box 378
Cayucos, CA 93430
Telephone: 805-995-1618
Facsimile: 805-995-1678
Email: mtierney-lloyd@enernoc.com

APPENDIX A

PRESENTATION OF ENERNOC, INC.

CPUC LTPP WORKSHOP
SEPTEMBER 7, 2012

ENERNOC
Get More From Energy

LTPP, Storage and Demand Response Workshop

Mona Tierney-Lloyd, Director, Regulatory Affairs

September 7, 20122

About EnerNOC

Proven Customer Track Record

- 5,600 customers across 13,000 sites with 8,300 MW's of demand response capacity in North America, Europe, Australia, and New Zealand
- 99% customer retention rate
- Highest industry customer satisfaction rating
- Over $500 million in customer payments/savings to date
- Simple, risk-free commercial agreements

Full Value and Technology Offering

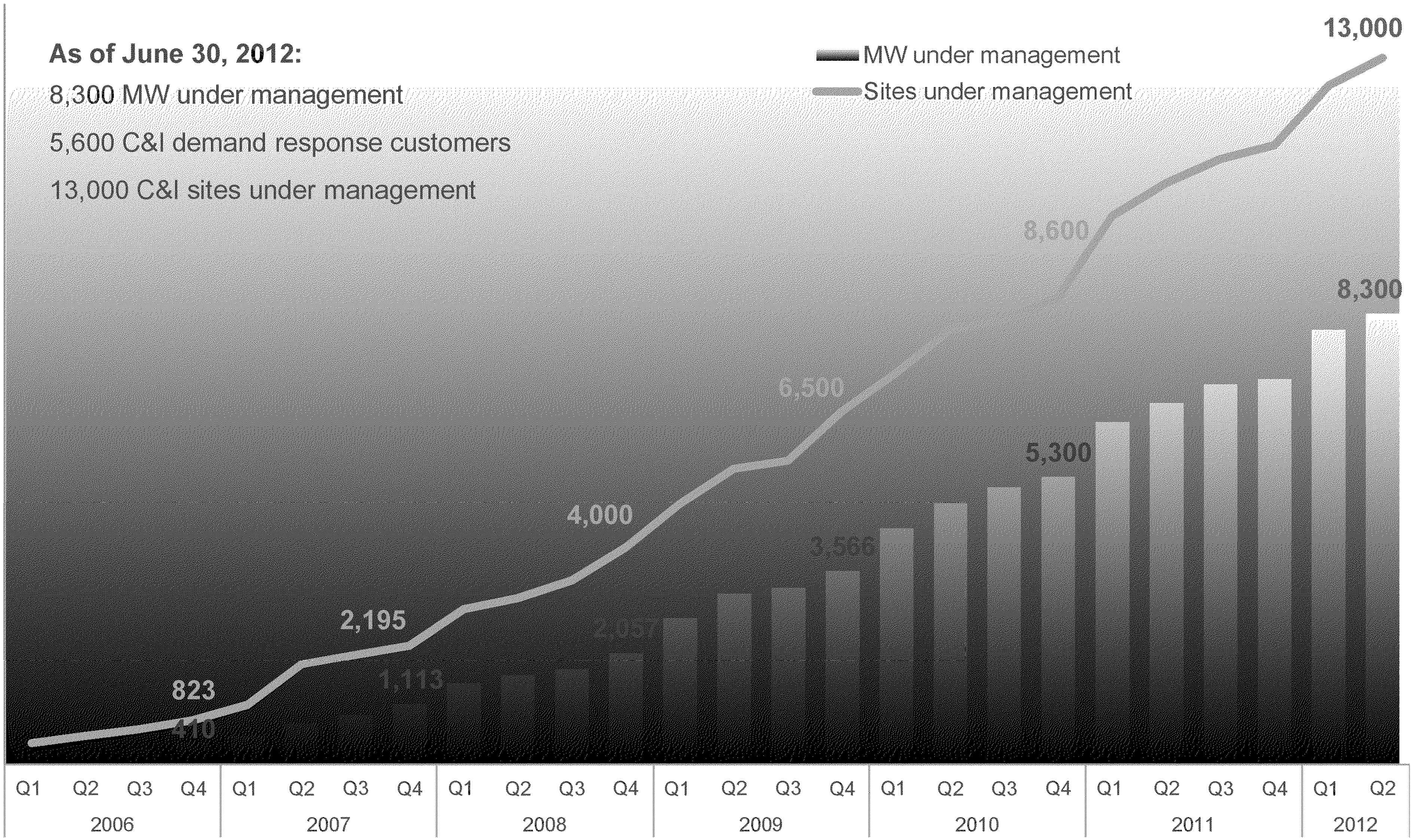
- Energy management application platform addresses demand and supply-side
- Combine technology, managed services, and market access
- More than $100 million invested to date in technology
- 24/7/365 Network Operations Center, real-time metering and web-based monitoring

World-Class Team and Resources

- 600 employees and growing fast – multiple "top places to work" awards
- Publicly traded on the U.S. NASDAQ (ENOC)
- Over $79 million in cash on balance sheet

ENERNOC

A History of Rapid Growth



ENERNOC

SB_GT&S_0197141

Agenda

- LTPP, DR and Renewable Integration
- Flexible Capacity and Technology
- Product Definitions
- Challenges
- RFOs

Discussion and Questions

ENERNOC

SB_GT&S_0197142

Scenario Synopsis

Increased Penetration of renewable distributed resources

Forecast retirement of existing gas-fired generation in LCAs due to OTC

Changes in the planning and operational needs of the system from a Peak Day (MW) to Operational Flexibility (MW/min) basis

To date, the only resources considered to meet this capability have been gas-fired generators

DR can provide a portion of the renewable integration need—development and removal of barriers

ENERNOC

Studies on Operational Impacts of Renewable Integration

GE Energy Study for NREL "Western Wind and Solar Integration Study" (May 2010)

Regulatory Assistance Project Study for the Western Governor's Association (June 2012)

Flexible capacity is one of several operational changes that need to be adopted to efficiently integrate renewable resources

- Expanded balancing area cooperation, including dynamic transfers
- Expand sub-hour dispatch and Intra-hour scheduling
- Improved forecasting of wind and solar
- Commit additional operating reserves
- Build or increase utilization of transmission
- **Target new or existing DR to assist with variability**

"It is more cost-effective to have demand response address the 89 hours of contingency reserve shortfalls rather than increase spin for 8760 hours of the year. Demand response can save up to $600M/ yr ($510M/yr in 2009$) in operating costs versus committing additional spinning reserves." NREL WWSIS at p. 22

ENERNOC

Long-Term Procurement Process

Local Capacity Requirements-Phase 1

- 10-Year Planning Horizon, expanded to 20-year horizon
- High load scenario (assume discounted DR materializes)
- Assume retirements of OTC plants
- Assume DG goals are met
- Assume 2400-3700 MW of LCR need in Southern California
- Assume only gas-fired generation will meet the need
- **Assume ZERO LCR capability is met by DR resources**
- Assume ZERO uncommitted EE

System Capacity Needs-Phase 2

- Scenarios are still being determined
- Under most scenarios, no system need for next 10 years
- **Assume no growth in DR as mid-range scenario (~5,000 MW)**
- Assume a +/- 10% of mid-range for high and low scenarios

On its face, the DR assumptions are inconsistent with EAP

ENERNOC

These Assumptions Are Pessimistic

DR Resources Can be Dispatched on a LCA Basis

- D.11-10-003 requires local dispatch for local RA credit
- Some DR is already locally dispatchable and more will be available in the near-term

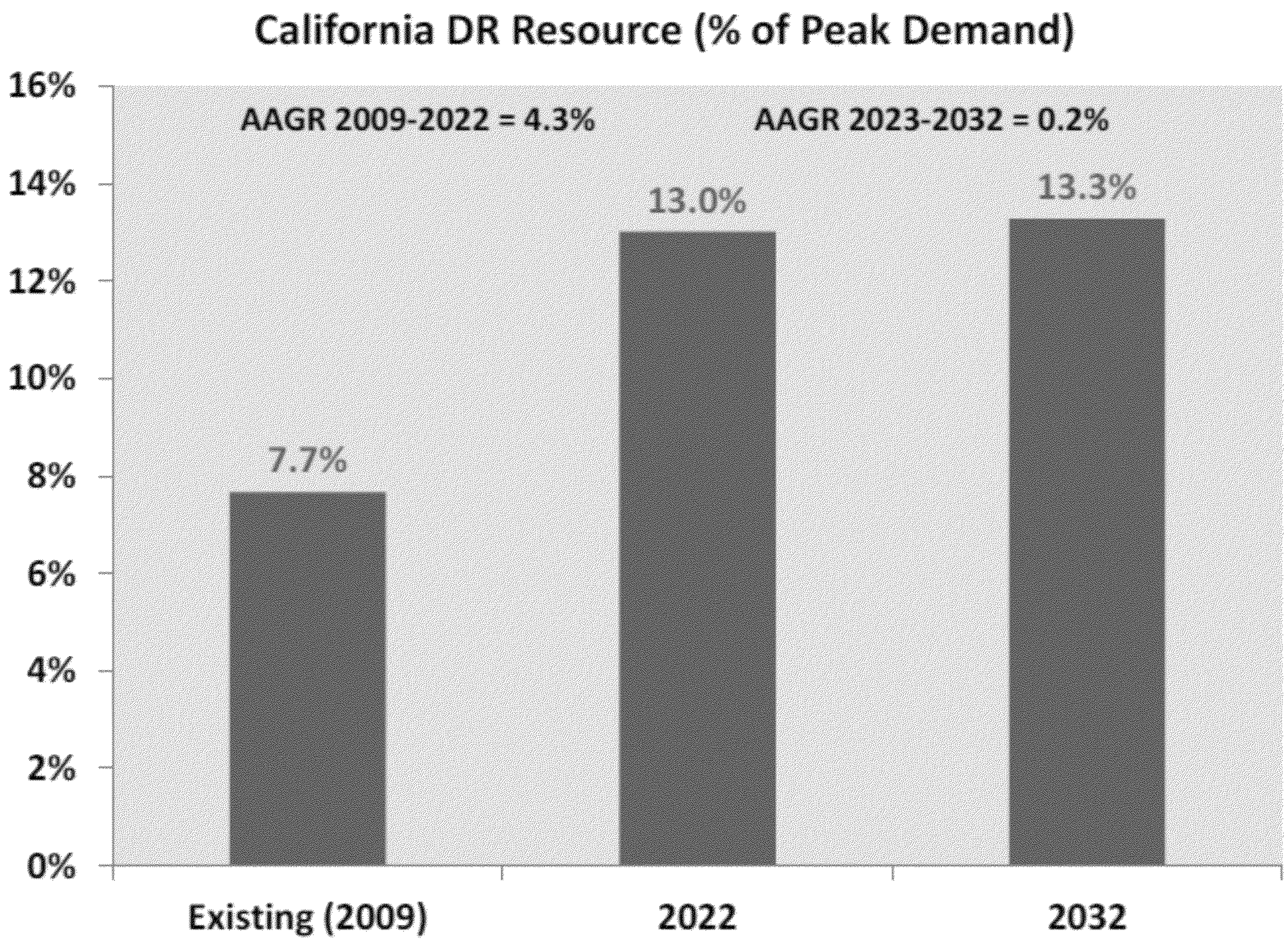
Directionally, technological capability and need is moving DR toward being a faster response resource

Technology, Smart Grid and Markets Will Expand DR Services

- Utility smart grid deployment plans expect additional DR and EE potential as a result of enabling technologies.
- OpenADR protocols and utility incentives will expand automated load response
- Data access protocols (OpenADE/ESPI, Zigbee, SEP 1.x or 2.0), HAN deployments
- Expanded access to markets, need for renewable integration

ENERNOC

California



The Brattle Group

SB_GT&S_0197147

Policy and regulatory drivers contribute to the variation in DR impacts

- Possibly the single most influential driver of DR market penetration is the extent to which state regulators support its development
- For example, California's Energy Action Plan prioritizes demand-side resources in the state's energy mix, and the California IOUs have built significant DR portfolios as a result
- Even a general policy focus on demand-side participation, such as Arizona's DSM energy reduction goal of 22% by 2020, has been shown to correlate with greater impacts from DR programs (Smith and Hledik, 2012)
- Support for innovative pricing schemes can also act as an indicator of future DR and dynamic pricing efforts; the Colorado PUC requires that the state's utilities offer an inclining block rate to residential customers
- States without policy support for demand-side initiatives, such as Montana and Wyoming, have demonstrated little DR market penetration

The Brattle Group

Various Forms of Demand Response

Supply-side, demand-side, and fast-response resources

Supply-Side Resources

- Capacity, economic or emergency energy, ancillary services
  - Still working on the rules for wholesale market participation in CA
  - Economic and logistical barriers

Demand-Side Resources

- Dynamic Pricing (CPP and PDP)
- DLC

Fast-Response Resources

- Under-frequency response
- Spinning and non-spinning reserves
- Regulation

All of these can provide benefits to the system by reducing demand and could displace some supply resources

ENERNOC

Summary of Navigant Survey of How DR Is Used by Other ISOs/RTOs, and by Two Utilities Where There Are No Organized Wholesale Markets

	Use of DR for Ancillary Services			Use of DR to Avoid Capacity	Use of DR to Avoid Energy
	Spinning Reserves	Non-Spinning Reserves	Regulation		
ERCOT	Yes (50% cap)*	Yes	Yes	Not Applicable	Yes
NYISO	Yes	Yes	Yes	Yes	Yes
PJM	Yes (25% cap)*	Yes	Yes	Yes	Yes
ISO-NE	No	No	No	Yes	Yes
MISO	Yes (10% cap)*	Yes	Yes	Yes**	Yes
BPA* **	No	No	Pilot Program (Load Following)	Yes	Not Applicable
HECO* **	No	Pilot Program	No	Yes	Not Applicable

KEY:
Yes/Pilot Program = DR is able to participate, although participation may still be limited (e.g., virtually no DR participates in ERCOT's non-spinning and regulation markets).

No = Market/service exists in that jurisdiction, but DR is not able to participate.

Not Applicable = Market/service does not exist in that jurisdiction.

* Maximum percentage of ISO/RTO's spinning reserve requirements that DR is allowed to provide

** Bonneville Power Administration (BPA) has a voluntary market

*** Hawaiian Electric Company (HECO) has no organized markets

Based on information available as of April 2012.

NAVIGANT ENERGY

ENERNOC

Flexible capacity must support ISO operational needs and align with existing market structures.

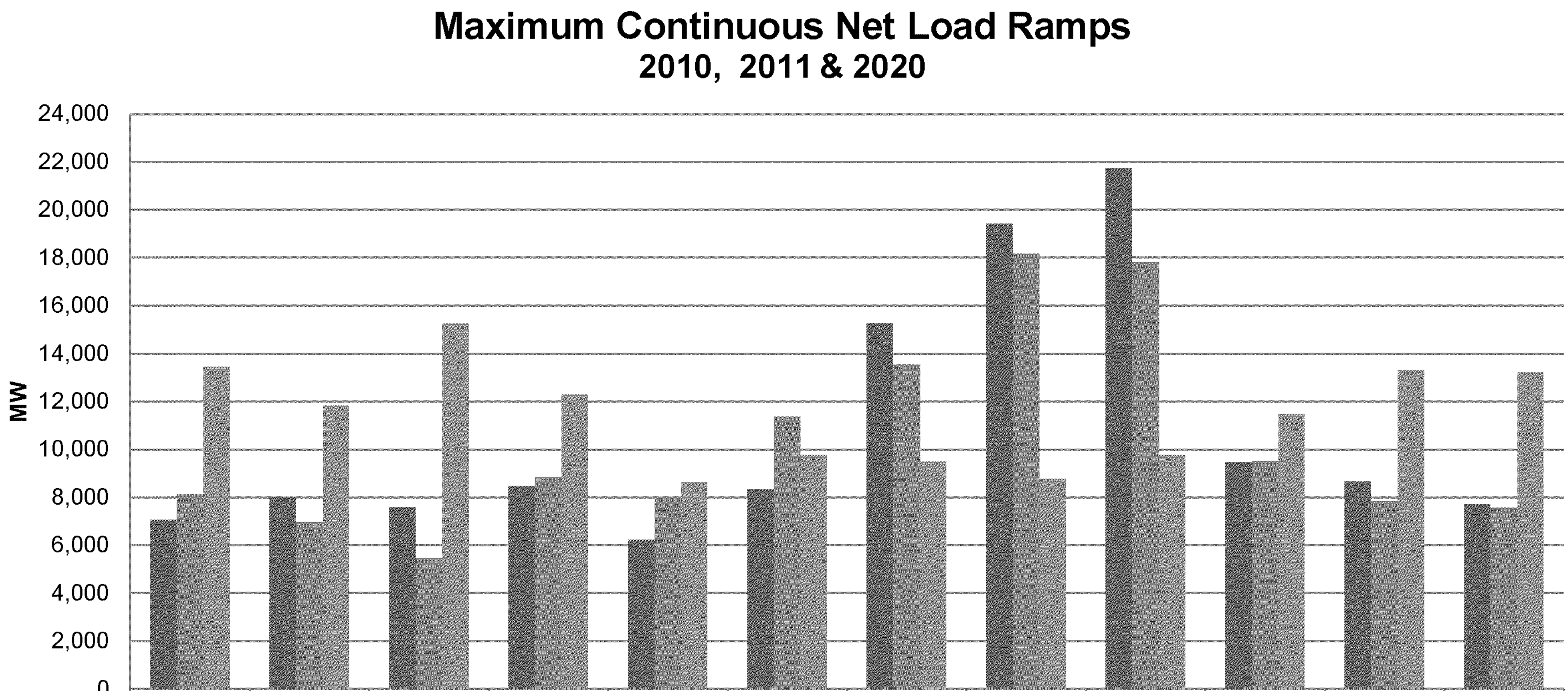
Three Categories of Flexible Capacity:

- **Maximum continuous ramping**
  - *The megawatt amount and duration by which the net load (load minus wind and solar) is expected to change continuously in a given direction within a month DR can blunt the ramp need.*
- **Load Following (≤ 60 minutes)**
  - *The maximum megawatts the net load is expected to change in a given hour of a given month DR can decrease net load*
- **Regulation (≤ 5 minutes)**
  - *The maximum megawatts the net load is expected to change between intra 5-minute dispatch intervals   More challenging*

ENERNOC

Maximum continuous net load ramps (trough to peak) -Actual 2010 & 2011--- Simulated 2020

Observation: Range of continuous ramp decreases in summer periods.

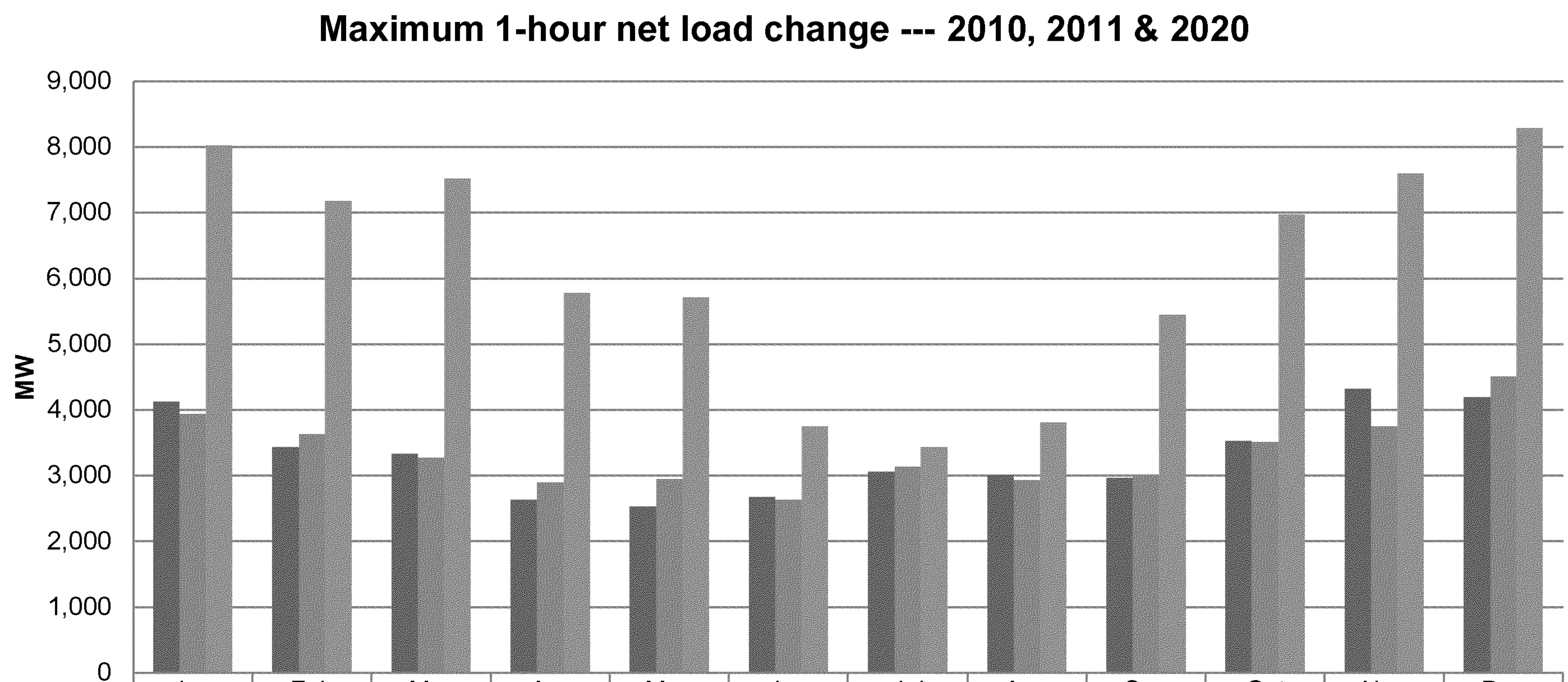


	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
2010	7,057	8,022	7,594	8,465	6,217	8,337	15,275	19,432	21,732	9,464	8,667	7,706
2011	8,133	6,982	5,453	8,859	8,000	11,382	13,544	18,181	17,824	9,510	7,855	7,577
2020	13,459	11,825	15,254	12,298	8,630	9,782	9,496	8,785	9,777	11,483	13,308	13,234

ENERNOC

Maximum 1-hour net-load change comparison --- Actual 2010 & 2011 --- Simulated 2020

Observation: Hourly changes increases in 2020 in shoulder periods.

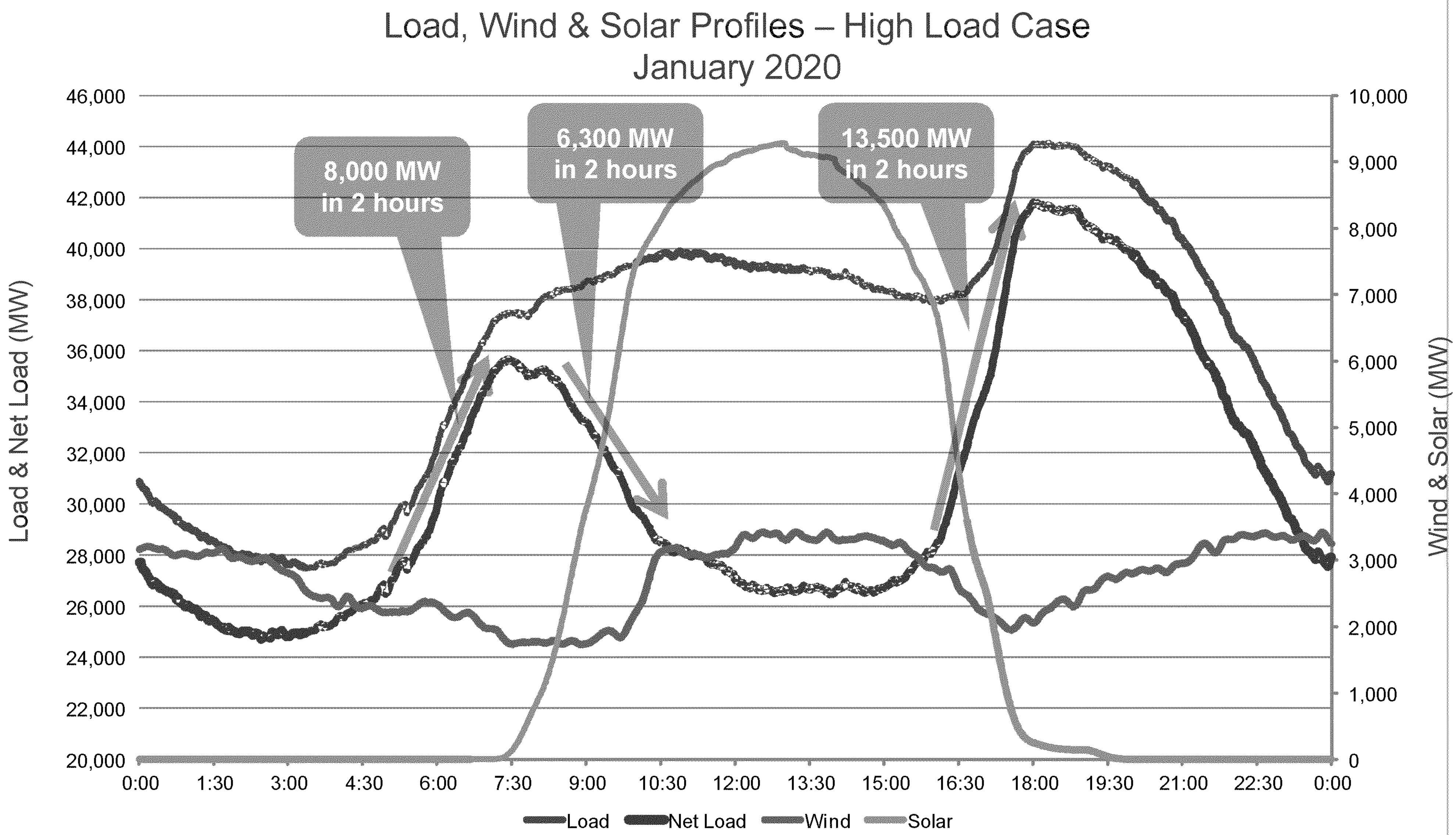


	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
2010	4,120	3,440	3,329	2,629	2,527	2,675	3,061	3,010	2,963	3,531	4,321	4,198
2011	3,935	3,630	3,271	2,897	2,951	2,637	3,137	2,933	3,004	3,514	3,746	4,506
2020	8,022	7,186	7,516	5,783	5,714	3,753	3,439	3,811	5,443	6,979	7,597	8,286

ENERNOC

SB_GT&S_0197153

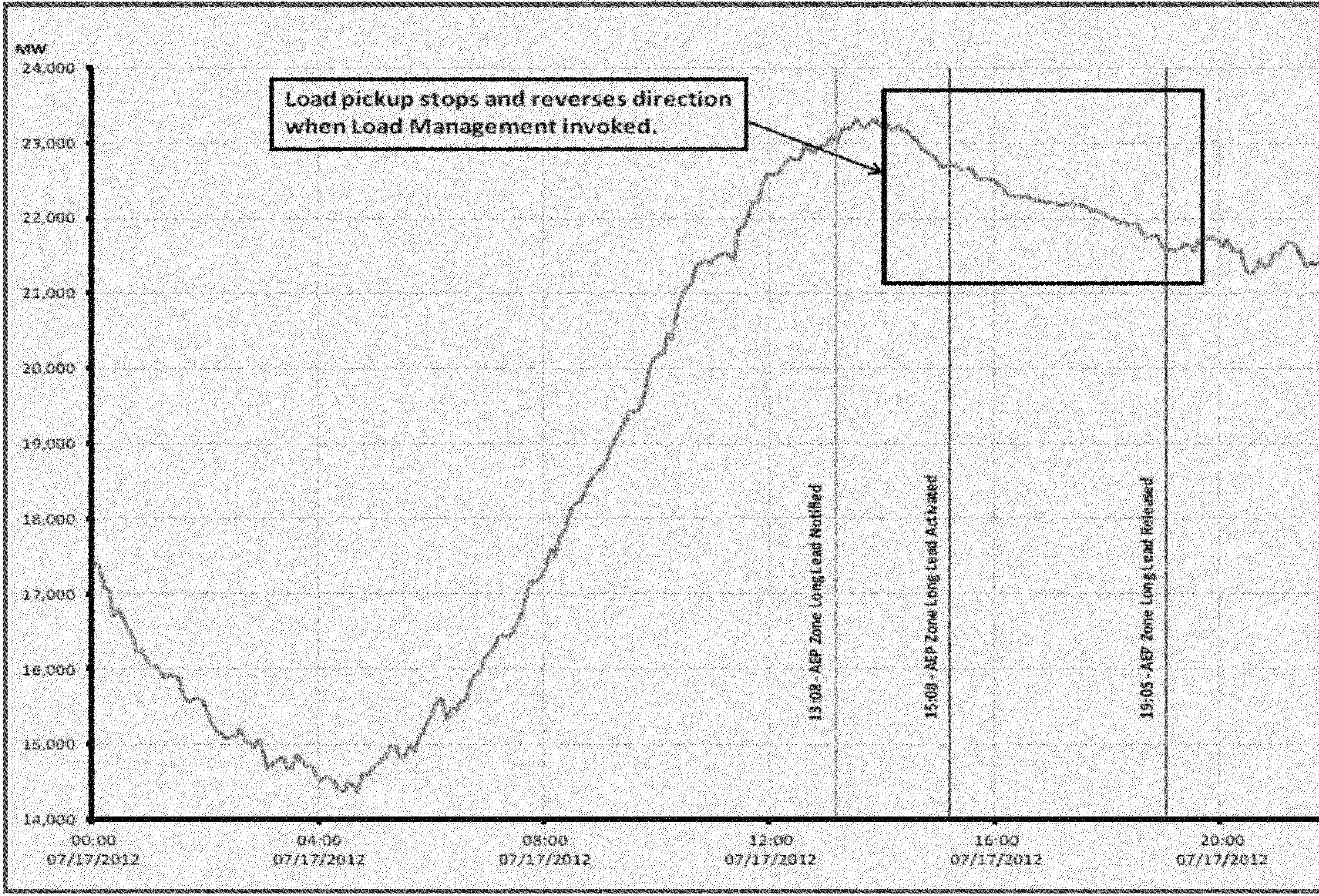
Conventional resources will be dispatched to the net load demand curve – High Load Case



ENERNOC

SB_GT&S_0197154

Instantaneous AEP Zonal Load 7/1



SB_GT&S_0197155

Challenges

Current Flexible Capacity Definitions are Designed for Generators

- Pmin and Pmax do not translate to load
- Not clear how DR would qualify for these services

Either define how DR fits under these definitions or create DR definitions

Product Definitions are not fully developed--Unknowns:

- Availability requirements
- Frequency or duration of dispatches
- Price/Value

Technological and Regulatory Barriers to Participation

- Telemetry
- WECC Limitations
- Cost-Effectiveness
- Developmental Stage

ENERNOC

Customer Perspective

Get the Incentives Right

- Customer payments should value the type of resource provided and included the value in cost effectiveness calculations
  - Fast response
  - Location-specific
  - Annual availability
  - Dispatch frequency/forecasting
- Customer automation incentives through utilities, include 3rd parties
- Education and acceptance

ENERNOC

Multi-Purpose Demand Response

In order to meet resource needs, DR portfolios will be asked to provide a variety of resources.

Emergency DR Resource (100 MW)

- *Typical dispatch: 6 hours duration; 1-2x/year; 60-minute notice*
- *Load reduction only*

Peak-shaving DR Resource (50 MW)

- *Typical dispatch: 4 hours duration; 10-15x/year; 30-minute notice*
- *Load reduction only*

Spinning and Non-Spinning Reserves DR (25 MW)

- *Typical dispatch: 30-minute to 2 hours duration; 10-50x per year; 10-minute notice*
- *Load reduction only*

Load-following DR Resource (15 MW)

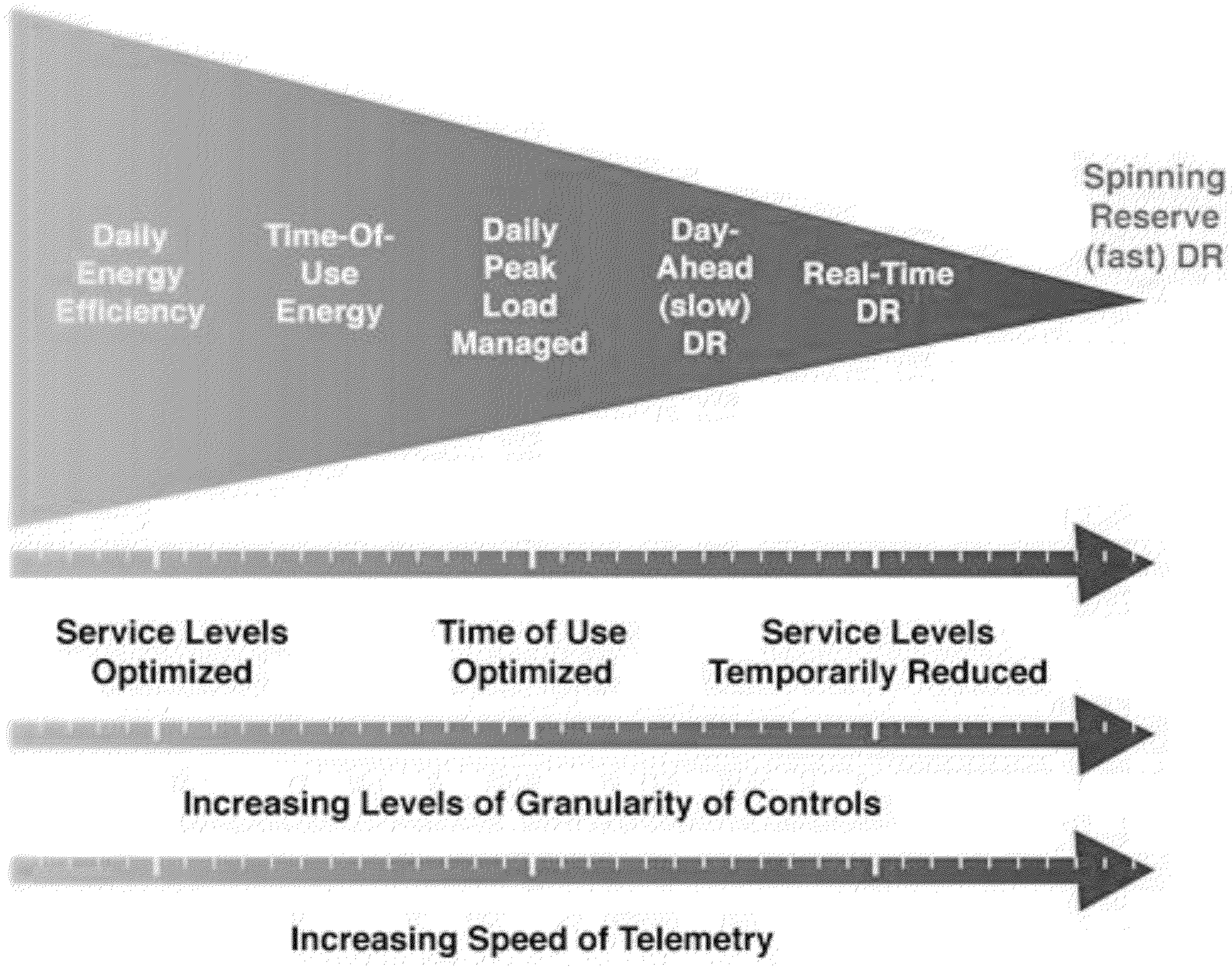
- *Typical dispatch: 1-2x/day; 30-minute duration; 5-minute notice*
- *Load reduction or increase*

ENERNOC

SB_GT&S_0197158

Accommodating varying levels of sophistication

Varying levels of technical rigor and customer sophistication are required for the various types of demand response, but ALL services provided by generation can also be provided by demand response



ENERNOC

SB_GT&S_0197159

[EnerNOC **Experience** with Quick Response DR

Some resources provide **ancillary services** or qualify as **spinning/non-spin reserves**

Approximately 1,900 sites in our portfolio feature automated remote dispatch

	Program	Notification	Max Event Length	EnerNOC Portfolio
Restructured Market	ERCOT Emergency Interruptible Load Service (EILS)	10 min	Up to 8 hours	**750+ Sites 380+ MW**
Restructured Market	ERCOT Load acting as a Resource (LaaR) - Responsive and Non-Spinning Reserves	Instantaneous to 10 min	No maximum	
Restructured Market	National Grid (UK) Short-Term Operating Reserves Market (STOR)	20 min	Up to 4 hours Average 45 minutes	
Restructured Market	PJM Synchronized Reserves Market (SRM)	10 min	Max 30 min. / Avg. ~23 min.	
Utility Bilateral	San Diego Gas & Electric Clean Gen	10 min	Up to 8 hours	
Utility Bilateral	PNM Peak Saver	10 min	Up to 6 hours	
Utility Bilateral	Salt River Project Power Partner	10 min	Up to 6 hours	

RFO Considerations

Maintain loading order priority and designate a % RFO set aside

All –source RFOs will try to fit the DR square peg into the generation round hole

- **Operating characteristics are different**
- **DR is not a base-load resource**

Make clear what products are being sought up-front and how DR can participate

- **Current definitions do not contemplate DR**

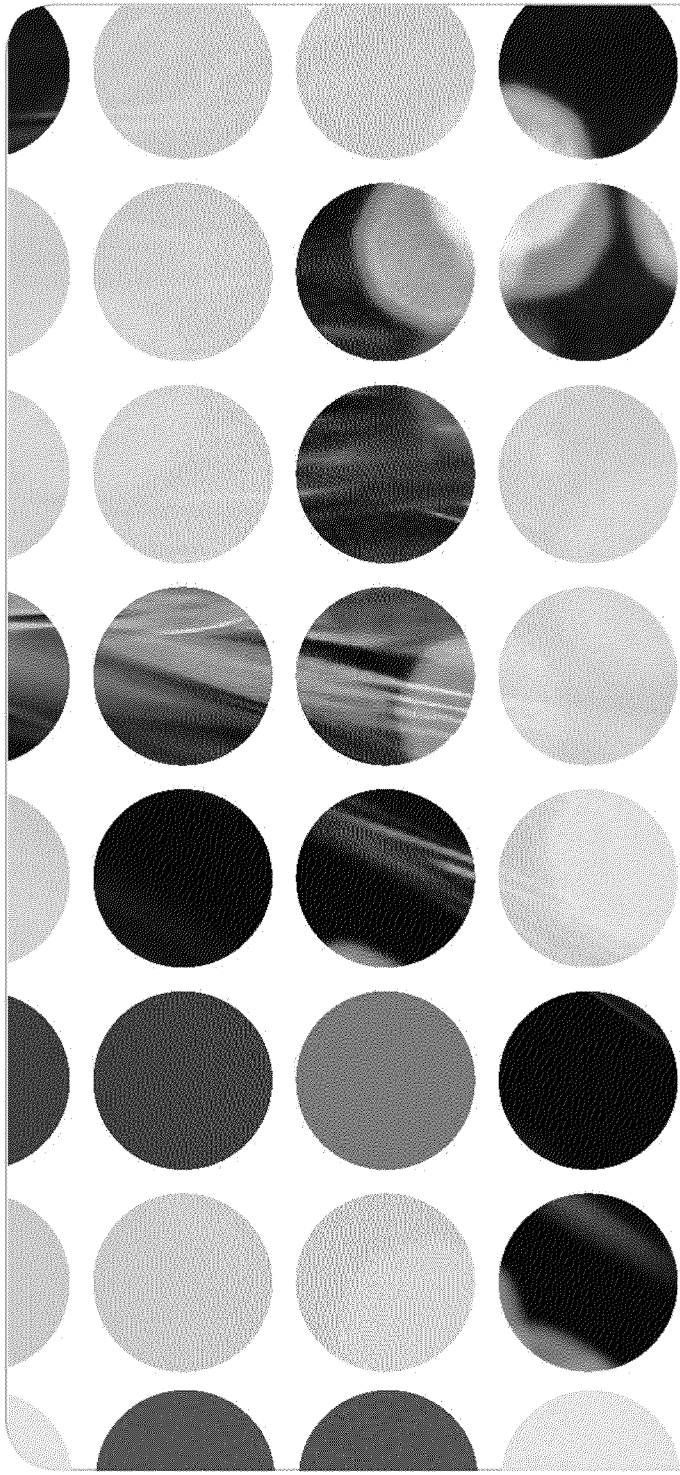
Stagger solicitations so that DR advances over time can be included

- **Capabilities are going to increase over time; don't lock out future potential**

Establish a value for fast-response resources, with locational characteristics that encourages participation and is higher than system, slow-response resources

- **This is a fundamental shift away from peak requirements resourcing**

ENERNOC



ENERNOC

Mona Tierney-Lloyd
Director, Regulatory Affairs
P. O. Box 378

Cayucos, CA 93430

(415) 238-3788
mtierney-lloyd@enernoc.com

APPENDIX B

CPUC ENERGY DIVISION

2013 Total IOU DR Program Totals by Program and Local Area Grossed Up for T&D Losses, SCE Program Totals

SCE DR 2013 Load Impact Estimates

Average Hourly Impacts (MW/hour) from 1pm to 6pm in May-Oct. and from 4pm to 9pm in Nov.-Apr.

			Expected Capacity at Coincident Peak based on Load Impact Protocols (MW)											
			Average of Hourly Ex Ante Load Impacts (MW/ hour) from 2 to 6 PM If Simultaneous Events Are Called on Monthly Peak Load											
Program Name	Payment$	Local Area	Jan-13	Feb-13	Mar-13	Apr-13	May-13	Jun-13	Jul-13	Aug-13	Sep-13	Oct-13	Nov-13	Dec-13
Agricultural and Pumping Interruptible (API)	1	LA Basin	5.28	6.22	5.63	7.47	8.08	6.55	5.52	5.56	5.12	8.06	8.75	4.67
		Big Creek/ Ventura	15.43	15.60	19.35	30.28	35.78	36.82	38.90	37.28	34.01	28.60	19.87	20.44
		Outside LCA	0.74	1.18	1.64	3.66	3.17	3.21	2.30	2.46	2.65	1.27	1.13	0.84
		Total IOU Service Area	21.45	23.00	26.62	41.40	47.04	46.59	46.72	45.30	41.79	37.93	29.75	25.96
Base Interruptible Program (BIP)	1	LA Basin	373.80	433.34	414.15	458.55	444.22	436.63	428.63	434.06	439.02	427.06	403.32	349.31
		Big Creek/ Ventura	80.37	71.73	73.76	93.69	95.62	97.62	89.32	91.28	99.76	86.59	88.77	78.50
		Outside LCA	63.03	73.01	66.08	75.27	78.41	59.54	71.23	73.62	62.52	68.79	76.97	54.22
		Total IOU Service Area	517.19	578.08	553.99	627.51	618.25	593.79	589.18	598.97	601.30	582.44	569.06	482.03
Summer Discount Plan (SDP) Commercial	1	LA Basin						17.68	28.77	39.46	34.27			
		Big Creek/ Ventura						9.75	12.22	13.34	11.37			
		Outside LCA						2.22	2.06	3.44	3.28			
		Total IOU Service Area	0.00	0.00	0.00	0.00	0.00	29.65	43.05	56.24	48.91	0.00	0.00	0.00
Summer Discount Plan (SDP) Residential	1	LA Basin						392.38	458.75	421.59	448.34			
		Big Creek/ Ventura						45.93	56.66	52.60	50.93			
		Outside LCA						40.60	53.50	50.02	48.59			
		Total IOU Service Area	0.00	0.00	0.00	0.00	0.00	478.91	568.91	524.21	547.86	0.00	0.00	0.00
Demand Bidding Program (DBP)	1	LA Basin	3.56	3.82	3.92	3.77	5.84	6.68	6.87	7.25	7.38	7.21	5.68	3.36
		Big Creek/ Ventura	1.24	1.27	1.32	1.18	1.71	1.97	2.01	2.07	2.09	1.99	1.68	0.97
		Outside LCA	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
		Total IOU Service Area	4.79	5.09	5.24	4.95	7.56	8.65	8.88	9.32	9.47	9.20	7.36	4.33
Capacity Bidding Program Day Ahead (CBP)	1	LA Basin					4.33	4.33	4.33	4.33	4.33	4.33		
		Big Creek/ Ventura					1.24	1.24	1.24	1.24	1.24	1.24		
		Outside LCA					0.15	0.15	0.15	0.15	0.15	0.15		
		Total IOU Service Area	0.00	0.00	0.00	0.00	5.71	5.71	5.71	5.71	5.71	5.71	0.00	0.00
Capacity Bidding Program Day Of (CBP)	1	LA Basin					16.52	16.52	16.52	16.52	16.52	16.52		
		Big Creek/ Ventura					3.95	3.95	3.95	3.95	3.95	3.95		
		Outside LCA					1.64	1.64	1.64	1.64	1.64	1.64		
		Total IOU Service Area	0.00	0.00	0.00	0.00	22.11	22.11	22.11	22.11	22.11	22.11	0.00	0.00
Demand Response Contract Day Ahead	1	LA Basin					7.23	7.45	9.11	9.79	10.39	10.54		
		Big Creek/ Ventura					2.53	2.58	3.17	3.39	3.62	3.66		
		Outside LCA					0.22	0.20	0.29	0.34	0.27	0.32		
		Total IOU Service Area	0.00	0.00	0.00	0.00	9.98	10.23	12.57	13.52	14.28	14.53	0.00	0.00
Demand Response Contract Day Of (DRC)	1	LA Basin					110.87	119.06	124.92	133.11	137.86	139.63		
		Big Creek/ Ventura					20.52	22.08	23.11	24.67	25.50	25.81		
		Outside LCA					9.41	10.15	10.61	11.35	11.75	11.88		
		Total IOU Service Area	0.00	0.00	0.00	0.00	140.80	151.28	158.65	169.13	175.11	177.32	0.00	0.00
Save Power Day (SPD)	0	LA Basin						161.73	161.73	161.73	161.73			
		Big Creek/ Ventura						24.38	24.38	24.38	24.38			
		Outside LCA						11.89	11.89	11.89	11.89			

		Total IOU Service Area	0.00	0.00	0.00	0.00	0.00	198.00	198.00	198.00	198.00	0.00	0.00	0.00
Critical Peak Pricing (CPP) Large	0	LA Basin						24.96	24.46	24.21	24.94			
		Big Creek/ Ventura						3.29	3.11	2.77	2.20			
		Outside LCA						1.08	0.91	0.88	0.97			
		Total IOU Service Area	0.00	0.00	0.00	0.00	0.00	29.32	28.49	27.86	28.11	0.00	0.00	0.00
Critical Peak Pricing (CPP) Medium	0	LA Basin						0.81	0.81	0.81	0.81			
		Big Creek/ Ventura						0.13	0.13	0.13	0.13			
		Outside LCA						0.06	0.06	0.06	0.06			
		Total IOU Service Area	0.00	0.00	0.00	0.00	0.00	1.00	1.00	1.00	1.00	0.00	0.00	0.00

Total, Allocated Event-Based Resources	LA Basin	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
	Big Creek/ Ventura	2267.94	3075.18	3113.79	2635.56	1824.57	1033.64	219.67	0.00	0.00	0.00	0.00	0.00
	Outside LCA	2267.94	3075.18	3113.79	2635.56	1824.57	1033.64	219.67	0.00	0.00	0.00	0.00	0.00
	Total IOU Service Area	2267.94	3075.18	3113.79	2635.56	1824.57	1033.64	219.67	0.00	0.00	0.00	0.00	0.00
Total Unallocated Event Based Resources	LA Basin	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
	Big Creek/ Ventura	682.67	909.78	909.78	681.46	641.47	414.11	186.74	187.48	0.00	0.00	0.00	0.00
	Outside LCA	682.67	909.78	909.78	681.46	641.47	414.11	186.74	187.48	0.00	0.00	0.00	0.00
	Total IOU Service Area	682.67	909.78	909.78	681.46	641.47	414.11	186.74	187.48	0.00	0.00	0.00	0.00
Total Event Based Resources	LA Basin	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
	Big Creek/ Ventura	2950.62	3984.96	4023.57	3317.02	2466.04	1447.75	406.41	187.48	0.00	0.00	0.00	0.00
	Outside LCA	2950.62	3984.96	4023.57	3317.02	2466.04	1447.75	406.41	187.48	0.00	0.00	0.00	0.00
	Total IOU Service Area	2950.62	3984.96	4023.57	3317.02	2466.04	1447.75	406.41	187.48	0.00	0.00	0.00	0.00

Payment$ - if payment for this program is from bundled customers only, enter 0, if all distribution customers, enter 1

Totals