

More Than Smart

Overview of Discussions Q3 2014 thru Q1 2015

Volume 2 of 2

March 31, 2015



Caltech



Vol. 2 Topics

New Distribution Planning Process (DPP)

- Distribution power engineering methods
 - From deterministic to probabilistic
- Integration (hosting) Capacity method
- Locational benefits methods
 - Value Components
 - Methods

Vol. 2 Introduction

- These slides represent a summary of the MTS Working Group discussions regarding the evolution of distribution planning in CA to implement the §769 requirements.
- This compendium includes slides used in the MTS WG over the past nine months to facilitate and summarize discussion.
- The purpose of this volume is to provide a source of information that may be useful to other states/countries considering the need to advance distribution planning to integrate DER at scale and realize its net value potential.
- The views expressed in these slides are those of the MTS WG and do not necessarily reflect the position or policy of the participating organizations or the State of California (except as clearly identified.)

Distribution Planning Process

Distribution Planning Process Evolution

Distribution Power Engineering

Integration Capacity Methods

Locational Benefits Methods

Distribution Resources Plan Requirements

CA Public Utility Code §769 Requirements related to Distribution Planning

DPP Focus

- Identifies **optimal locations** for the deployment of Distributed Energy Resources (DERs)
 - DERs include distributed renewable generation, energy efficiency, energy storage, electric vehicles, and demand response
- Evaluates **locational benefits and costs** of DERs based on reductions or increases in local generation capacity needs, avoided or increased investments in distribution infrastructure, safety benefits, reliability benefits, and any other savings DERs provide to the grid or costs to ratepayers

Guiding Principles

- The MTS discussions at Caltech in June 2014 produced a set of Guiding Principles for Distribution Planning that captured the consensus of the group regarding implementation of Sect. 769 requirements
- The Guiding Principles are also aligned with federal policies and leverage industry research and best practices that were reviewed as part of the MTS effort

DPP Guiding Principles

Guiding Principles	Potential Requirements
<p>P1: Scenario-driven integrated planning analysis framework</p>	<p>P1a: Framework should identify all relevant analysis and modeling interdependencies and related engineering-economic trade-offs P1b: Planning should use scenario driven “futures” using a set of common parameters including customer DER adoption, and other critical factors P1c: Planning should establish baseline functionality of current infrastructure and designs</p>
<p>P2: Standardized methodology and tools for distribution planning</p>	<p>P2a: Planning should be performed using a consistent set of accepted engineering and economic methodologies, but remain vendor and modeling technology neutral P2b: Engineering models and tools should address all relevant power system characteristics and dynamics for a well defined distribution area and inter-related local transmission system consistent with best practice</p>
<p>P3: Greater access to grid operational and market planning data</p>	<p>P3a: Utility asset and operational data used for distribution planning should be accessible to 3rd parties and researchers under certain qualifications and subject to confidentiality and security conditions. P3b: Market planning data from DER developers and services firms will be available to utilities and research institutions for relevant distribution and bulk power system planning under specific conditions and subject to confidentiality</p>
<p>P4: Integrated multi-stakeholder distribution planning process</p>	<p>P4a: Planning scope should involve relevant stakeholders, including representatives of customers, in process P4b: Stakeholder engagement should not create a bottleneck to planning process</p>

Distribution Planning Process – An Evolution

- The Distribution Planning Process (DPP) must evolve to realize California’s vision for making Distributed Energy Resources (DER) significant contributors to resource adequacy and safe, reliable operation of a “node-friendly network system”
- The first step in the DPP evolution is to produce a Distribution Resource Plan (DRP) which meets AB327/Sect. 769 requirements
- The MTS effort focused on defining a new integrated engineering-economic framework for distribution planning and development of a DRP focusing on:
 - Articulation of DPP current state – DRP In Today’s Context
 - Interpretation and agreement on what Policy requires
 - Articulation of DPP future state given AB327 requirements and other drivers and define “gaps”
 - DRP Analysis Implications
 - Identify key methodologies to define/clarify/agree to
 - Process Implications
 - Recommendation(?) for the Analysis, the Process & the Methodologies
 - DRP Distribution Power Engineering Methods
 - Evolve from deterministic to probabilistic
 - DRP DER Integration (Hosting) Capacity Methods
 - DRP DER Locational Benefits Methodology
 - Value Components
 - Calculation Methodologies
 - Alignment with CPUC Final Guidance

Distribution Resource Planning in Context

- 80+% of distribution feeder level investments planned and deployed on 1-2 year cycles
 - Circuit upgrades, equipment (e.g., transformers, switches) replacements & reconductoring
- Substation and system-wide technology deployment planning horizon between 5-7 years
- Distribution Planning Areas (DPA) are dissimilar among the IOUs in terms of distribution system scope and relationship to transmission system
- DPAs are not necessarily associated with specific Transmission Planning Areas (TPA)
- IOU Distribution system planning criteria adequately addresses reliability, capacity and safety and should be a foundational basis for DRP analysis
- DER Planning Issues
 - Lack of locational information regarding DER behind the meter
 - Gross Load forecasts and shapes from CPUC/CEC are insufficiently granular to a substation/feeder level
 - SDG&E Residential time of peak and alignment with DER output

DPP Evolution – Defining the Scope

- The MTS Working Group (WG) focused on interpreting what the policy objectives and requirements were
 - Scope and Timing
 - Elements
 - Analysis Implications
 - Dependencies
- The following slides illustrate the discussion and information exchange that MTS WG used to develop:
 - Initial thinking on the analysis framework and
 - Scope and timing of initial and ongoing DPP

Scope of Analysis in the Context of PUC 769

- Identify the scope of analysis in the context of AB 327 and define planning objectives and parameters to a level sufficient to conduct detailed analyses
- Analyses needed to determine integration capacity for DER
 - Integration capacity is not a single value, but rather a range of values that varies with type of DER, level of granularity, and by location.
 - How is “integration capacity” and “anticipated DER growth” determined?
 - Are there commercially available tools for the analysis?
 - How do we address the gaps in analysis at system interfaces?
 - How are we deciphering which parameters to include in the data sets?
- Analyses to determine locational value - benefits and costs associated with each DER type
 - Define:
 - **“Locational benefits”**
 - **“Optimal location”** (e.g., clarity regarding location in the context of the entire power system)
 - **“Value optimization”** (e.g., value maximization and/or cost minimization)
 - **Reliability and resiliency**

Integrated Distribution Analysis Framework

- Identify the scope of analysis in the context of AB 327 and define planning objectives and parameters to a level sufficient to conduct detailed analyses
 - Incl., questions such as treatment of DER as load modification
- Identify and define the specific elements that need to be assessed and the method of analysis, plus potential standardized approaches to:
 - DER adoption forecast
 - Load growth forecasts
 - Cost analysis
- Identify the interdependencies (e.g., data, assumptions, timing, etc) among the elements overall analysis as well as those with other related analysis.
 - E.g., Interdependencies between customer adoption analysis and power system engineering analyses, optimal locations.
 - Relationship between distribution planning and IEPR, EE forecast and CAISO Transmission planning, for example
- Identify gaps in AB327 objectives clarity, data and/or modeling tools to perform the various analyses

Distribution Planning Process (DPP)

- Two step approach given the short time between ruling and statutory deadline of July 1, 2015
- Focus 2015 Distribution Resource Plan (DRP) on:
 - Identifying current DER¹ “integration” capacity based on existing and near-term planned (i.e., already authorized investments)
 - **Integration capacity is not a single value, but a range of values, it varies with type of DER, level of granularity, and by location.**
 - Comparison of current integration capacity with anticipated DER growth
 - Prototyping locational benefits analysis for one (1) Distribution Planning Area within each IOU
 - Refine stakeholder engagement model
- Ongoing DPP
 - Annual distribution system DER integration capacity updates via revised RAM maps
 - Bi-annual DRP to include system-wide Location Benefits analysis at the substation level that could serve as input into General Rate Cases and inform IEPR/LTTP/TPP processes

(Note: the DPP and LTTP/IEPR/TPP have significantly different inputs and outputs but one can inform the other)

¹ Term DER includes all forms of Distributed Generation, Demand Response, Energy Storage, Electric Vehicles and Energy Efficiency

DPP and Scenario Parameters

- Define distribution planning process
 - Identify period planning timeline: initial 2015 vs Ongoing
 - Relationship to other scenario based planning (e.g., CAISO, IEPR, EE, other)
- Define baseline scenario: “Current Path”
 - Baseline conceptually includes current investment plans and smart grid roadmaps but needs further clarification and articulation
 - Consider how to incorporate existing distribution capabilities
 - Identify and define scenario parameters, for example:
 - Time horizon: e.g., 20 or 25 years
 - Socioeconomic parameters
 - DER technology parameters
 - Financial/macroeconomic parameters
 - Policy parameters
 - Identify and define axis for scenarios
 - e.g., Policy & Customer Expectations
 - Discuss how to incorporate signposts into the scenario plans to illustrate trends that would suggest pathways to an outcome
 - Identify considerations for current investment and smart grid roadmaps, and EPIC portfolios based on scenario parameters

Work Products as Needed: Briefing Paper, Templates, Examples, Presentation

DRP Scenario Parameters

- Scenarios loosely linked to IEPR/LTPP assumptions and scenarios
 - CPUC/CEC DER/EE load forecasts will be the basis for inputs to DPP but will need to be more granular to be directly applicable
 - In near term, it is likely that each utility will need to develop bottom-up Gross Load, EE & DER forecasts that inform CPUC/CEC LTPP bulk system/climate zone forecasts
 - Need to address gap in insufficient DER adoption data and forecasting detail for distribution planning purposes (more discussion in the Planning Analysis F2F on 9/23)
 - LTPP assumptions only consider energy and generation capacity and not the values associated with distribution planning and operations
- Three DRP scenarios:
 - **“Trajectory”** modified case as base case
 - Leverage LTPP Trajectory case generically but modify using more granular distribution specific forecasts for; Gross load, Energy Efficiency, DER diffusion by type at a DPA level (?)
 - **“High DER”** to assess higher than Trajectory customer adoption of DER
 - Each IOU specified variations on pace and magnitude of DER diffusion in their area based on service area specific customer characteristics, including socioeconomic, demographic, buying behavior as well as policy factors, for example
 - **“Expanded Preferred Resources”** case with policy driven DER diffusion based on increased renewables goals that incorporate distributed and behind the meter assets
 - Preferred Resources target set by CPUC and case variations for each IOU will be developed based on Resources Adequacy and other customer and service area specific characteristics

2015 DRP

- System-wide DER integration “integration” capacity assessment
 - Substation level DER integration capacity (minimum level)
 - Engineering analysis based on specific locational (load/DER/feeder) information, not “15% rule” heuristics, recognizing that the unique characteristics of each feeder will determine the integration capacity to integrate DER
 - Comparison of existing & near-term changes to integration capacity to anticipated DER growth
 - Continue to use existing distribution system planning criteria and guidelines, including capacity to support “1-in-10” year heat event and enable adjacent circuit load carrying in the event of circuit outage
 - Revise Renewable Auction Mechanism (RAM) maps to convey distribution system capacity for DER integration
 - Modified RAM maps are convenient means to communicate integration capacity availability
 - Current maps use the static 15% rule, which is no longer appropriate and will require more complete engineering analysis largely completed by IOUs
- Locational benefits analysis for one (1) Distribution Planning Area (DPA) as defined uniquely by each IOU
 - 10 year scenarios (3) driven DPA locational benefits analysis
 - More granular “Trajectory” scenario
 - High DER growth based on customer adoption greater than trajectory
 - Preferred resources growth based on increased use of DER to address bulk power and resource adequacy needs
 - Locational benefits conducted at the distribution substation level
 - Results will be used to:
 - Validate scenario and optimal location methodology and processes
 - Use as prototype for biennial DRP process
 - Use to prototype stakeholder feedback on process and results

Ongoing DPP: Annual DER Capacity Updates

Provide annual updates via modified RAM maps on feeder capacity to integrate DER

- Distribution system is changing annually on multiple dimensions:
 - Aging infrastructure replacement
 - Load growth and existing load density
 - Distribution system capacity and reserve
 - Grid modernization investments (incl. Smart grid)
 - Circuit reconfigurations
 - DER diffusion
 - Gross load profiles
- Update feeder level engineering analysis to determine the capacity of each feeder/substation to integrate DER
 - Use criteria and methods from 2015 DRP
- Leverage Renewable Auction Mechanism (RAM) maps to convey distribution system capacity for DER integration
 - Modified RAM maps are convenient means to communicate capacity availability

Ongoing DPP

- Annual updates to feeder level DER integration capacity
 - IOUs can provide annual updates to feeder capacity and publish via modified RAM maps
 - Compare existing integration capacity to anticipated DER growth
 - As in 2015, the engineering analysis will be more sophisticated and will not be based on the static 15% Rule
- Bi-annual DRP aligned with GRCs & broader CA planning
 - 10 year scenario driven system-wide locational benefits analysis
 - Locational benefits conducted at the distribution substation level
 - DRPs done by each IOU concurrently starting in 2017
 - Planning assumptions linked to CPUC/CEC inputs to IEPR/LTPP/TPP
 - Bi-annual DPP Process timing aligned with GRC process and CA Joint Agency planning schedules

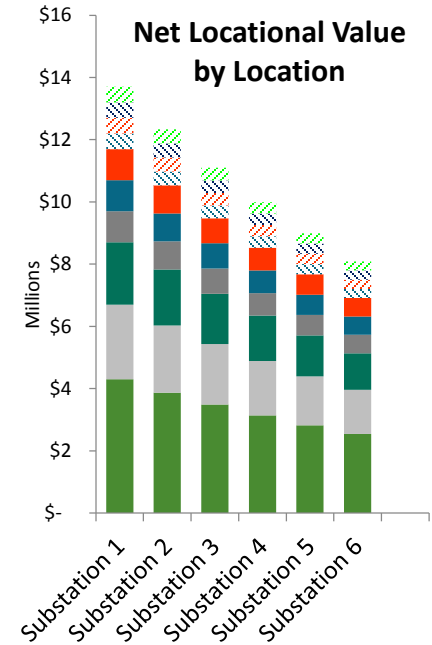
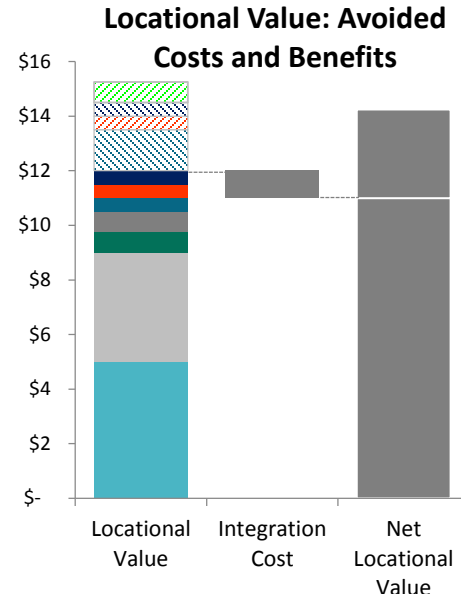
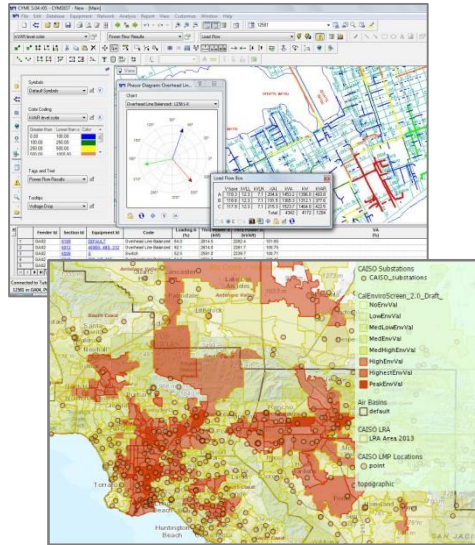
Distribution Planning Process

For Each DPA & Substations/Feeders

Annual Dist. Planning & Integration Capacity Analyses

Biennial DRP Locational Value Analysis

Identification of Optimal Locations



Distribution Planning Process Summary

Analysis	Action	Scope	Granularity	Timing
Integration Capacity <ul style="list-style-type: none"> Existing, available distribution capacity for DER interconnections 2yr Snapshot-in-time view that also reflects IOU investment plans 	<ul style="list-style-type: none"> Power flow analysis per feeder Utility to communicate via modified RAM maps 	2015 & Ongoing: <ul style="list-style-type: none"> All distribution feeders 	<ul style="list-style-type: none"> Feeder level 2yr outlook 	<ul style="list-style-type: none"> Every year
Optimal Locations <ul style="list-style-type: none"> 10yr Scenario driven analysis <ul style="list-style-type: none"> Trajectory High DER Preferred Resources Based on distribution capacity & operational services, transmission capacity, generation capacity & energy, BPS ancillary services, environmental, and other avoided costs/benefits Planning assumptions linked with CPUC/CEC/IEPR/LTPP/TPP planning 	<ul style="list-style-type: none"> Utility investment plans in GRCs and other reflect DER alternatives based on scenario driven locational benefits analysis Consider customer DER growth rates independent of central planning Utility to procure DER services via programs, tariffs, RFOs, etc. Utility to identify optimal locations via RAM type maps 	2015: <ul style="list-style-type: none"> One (1) Distribution Planning Area Ongoing: <ul style="list-style-type: none"> System-wide beginning in 2017-18 	<ul style="list-style-type: none"> Minimum - Substation level by DPA 10 yr outlook 	<ul style="list-style-type: none"> Every 2 years



Distribution Power Engineering

Distribution Power Engineering

- The following slides present some of the key topics and summarize discussions that MTS WG considered when looking at implications of DER integration and the DRP development on Distribution Power Engineering processes, methodologies and tools
- Included are examples of utility Distribution Power Engineering current state and changes implemented to better incorporate DER integration in distribution planning and engineering

Distribution Power Engineering

- Distribution designs today generally reflect a traditional set of assumptions and uses for a distribution circuit.
- Standard engineering design practices are often based on 50 year old operating paradigms. This may lead to significant stranded investment risk beginning in the next decade.
- Distribution designs must evolve to align to the new requirements driven by customer choices and public policy.
- Distribution system designs, investment decisions and related technology adoption processes for physical infrastructure, protection and control systems and operational systems need to quickly evolve toward achieving the following in a cost effective manner and mindful of customer rate impacts:
 - Grid as open network model to enable seamless DER/microgrid integration
 - Employ flexible designs and layered architecture to create flexibility while managing complexity
 - Align timing of infrastructure/systems deployment with needs
 - Well defined and functioning utility advanced technology on-ramp

Traditional Electric System Planning

Distribution Planning

- Highly variable due to customer mix, microclimates, reconfigurations
- Radial configuration, relies on circuit ties to reconfigure system
- Increasing complexity with variable resources
- Emerging role for an integrated grid to facilitate distributed resources

Transmission Planning

- More predictable aggregate load behavior, relatively static configuration
- Network configuration, relies on redundancy and ability to change power flow
- Increasing complexity with large renewable integration and conventional generation retirements
- Established resource procurement through Long Term Procurement Process

Example: SDG&E Current Process

- SDG&E creates yearly distribution non-coincident circuit forecast
 - Adverse weather factors included to get to 1 in 10 year load
 - Individual areas modified to bring non-coincident to within 1.5% of coincident peak
 - DER effects ignored
 - 5 year detailed forecast, 10 year summary forecast
- SDG&E identifies capital projects to eliminate forecasted overloads on circuits and substations
 - Circuit re-conductors
 - New circuits
 - Substation transformer additions
 - New substation projects

SDG&E: The Path Forward – Methods

- Forecasting methodology modifications
 - Incorporate effects of installed DER
 - Reduced load due to PV/COGEN/Storage
 - Determine capacity factors for DER
 - PV approx. 35% at coincident peak
 - Storage = ??
 - Incorporate more detailed long range forecasting past 10 year horizon
- Project selection
 - SDG&E is now evaluating DER alternatives in addition to traditional projects
 - Optimal locations are under review for DER based on the following criteria
 - Deferred/avoided capital projects
 - Cost effectiveness
 - Reliability benefits
 - Reduced LCR

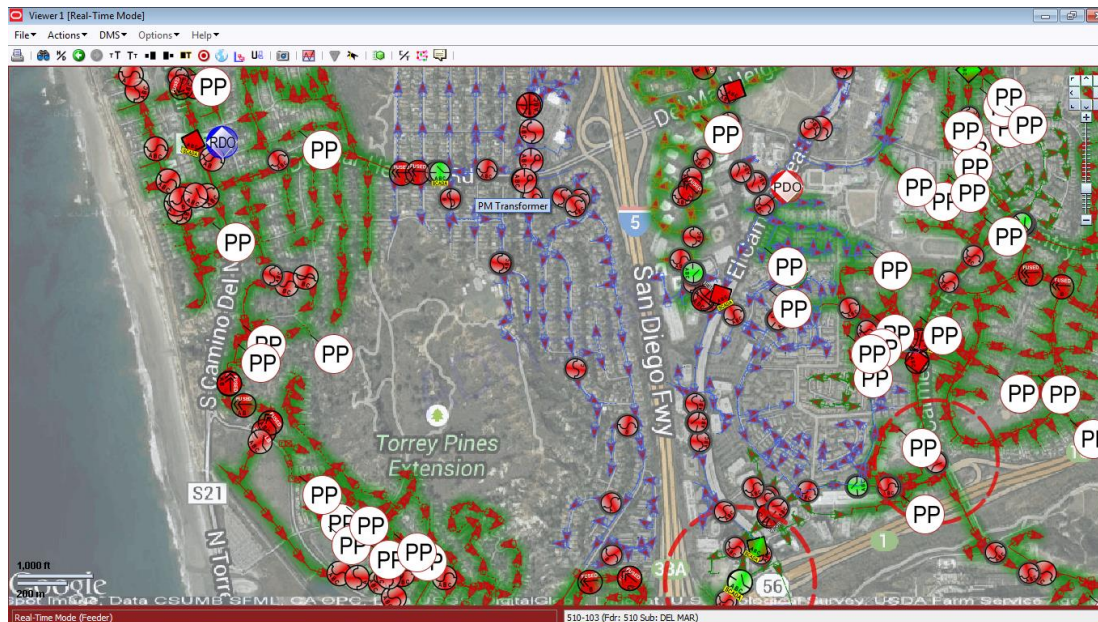
SDG&E: The Path Forward – Methods

- SDG&E contracted consulting firm to examine forecasting methods. Key recommendations:
 - Incorporate DER data into forecast
 - Utilize GIS data in short and long-term forecast
 - Improve weather normalizing process
 - Utilize econometric data (projections, zoning, permit data, etc)
 - Use a “smarter” algorithm, less reliant on planner discretion
- Where SDG&E sees the industry headed
 - Integrated short and long-term forecasting
 - Need time for EE, DR, and other tools to show effects
 - Environmental concerns drive longer project timelines
 - More automation in the forecasting process

SDG&E: The Path Forward – Tools

- Leverage existing systems – AMI, GIS
- New systems are in development
 - ADMS – Advanced Distribution Management System
 - Overarching control system to manage distribution system
 - Voltage/VAr control
 - Real time power flow/switching
 - Will issue commands to DERMS depending on system needs

Phase 1 ISD – March 2015



Planning Enhancements: Optimal Locations

Strategically-sited Distributed Energy Resources can provide additional value to the grid.

- AB 327 requires submittal of a distribution resource plan proposal to identify optimal locations for the deployment of distributed resources
- Existing public interconnection maps (Fig. 1) will be refined and expanded to better facilitate strategic project siting
- New layers may provide data on potential system benefits, future projects to alleviate constrained areas, etc.
- A formal process for updating and maintaining data based on interconnection and planning processes will be established

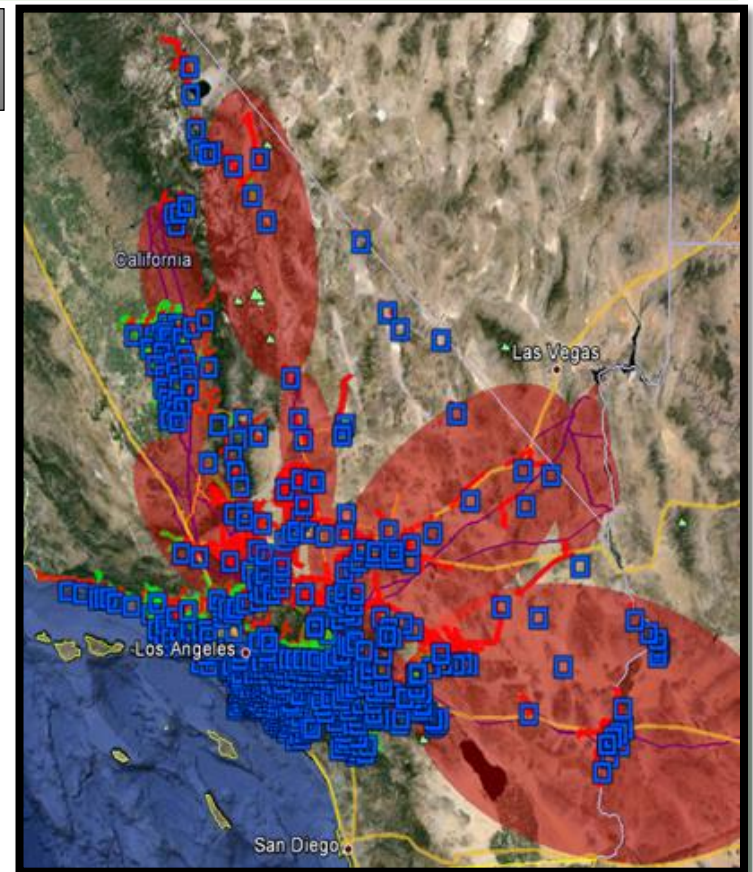
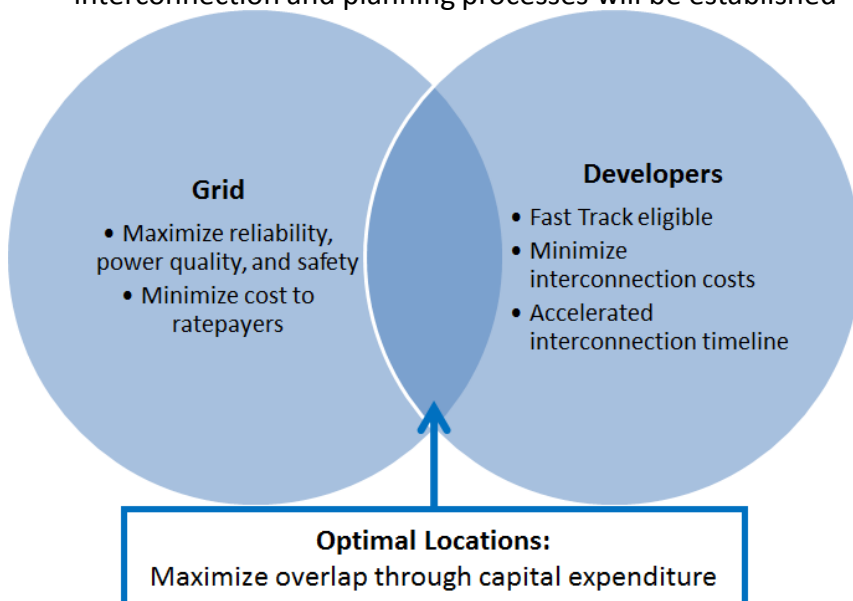


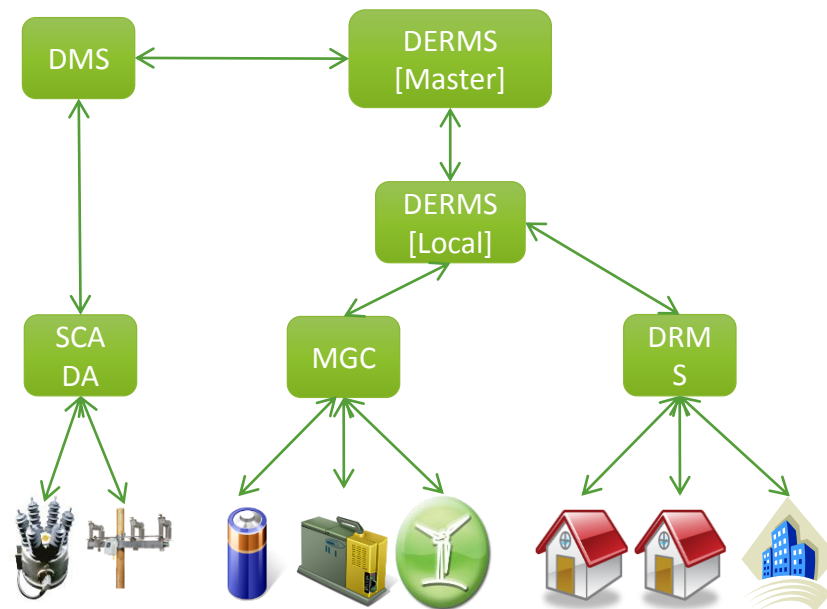
Figure 1: Interconnection Map Overview

Distribution Planning Enhancements

- Load forecasting methods and tools to model variable behavior
 - Optimal locations with high penetration
 - Required to reduce complexity of interconnections
- Modified criteria
 - Model variability of distributed resources to develop enhanced reliability criteria
 - Match load profiles in distribution circuits
- Grid operations
 - Match simulations to real time operations
 - Voltage and capacity deficiencies

SDG&E: The Path Forward – Platform

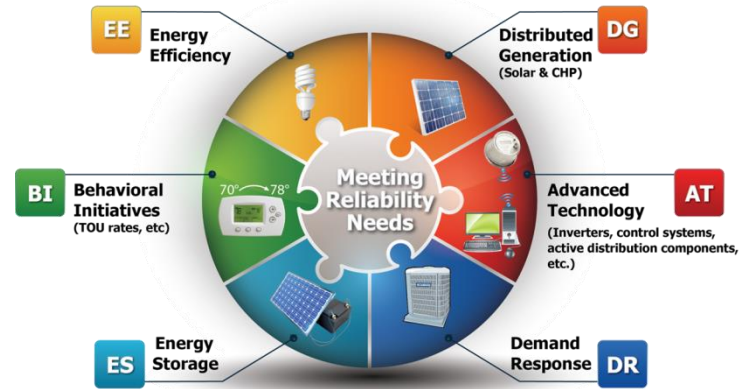
- DERMS – Distributed Energy Resource Management System
 - Will talk directly to Smart Inverters to manage local issues and deliver system commands
 - Issue set points to Smart Inverters
 - Aggregate data for backhaul to ADMS/NMS



Preferred Resources Pilot (PRP)

• Objectives

- Measure the local grid impact of Preferred Resources
- Implement a Preferred Resources portfolio to address local transmission needs
- Demonstrate Preferred Resources can be used to meet local capacity requirements
- Minimize/eliminate the need for gas fired generation at these locations
- Identify lessons learned for application to other grid areas



• Scope

- Regions served by Johanna and Santiago sub-stations
- “Preferred Resources” that meet the definition for energy efficiency, demand response, renewable resources, clean distributed generation, and energy storage
- Processes used to evaluate and deploy Preferred Resources



Integration Capacity Methods

Integration Capacity Analysis

- MTS WG recognized that hosting capacity analysis was needed to establish the baseline for locational benefits analysis
- MTS leveraged the hosting capacity methods proposed by IREC and EPRI in the discussions
- The term “hosting” was viewed as inconsistent with CA perspective on DER integration, so the term “integration” capacity is used instead. These terms are synonymous.
- Hosting Capacity Papers Reviewed:
 - Interstate Renewable Energy Council, 2014
 - Integrated Grid Benefit-Cost Framework, EPRI, 2015
- Following slides highlight the key discussion points

Integration Capacity Analysis

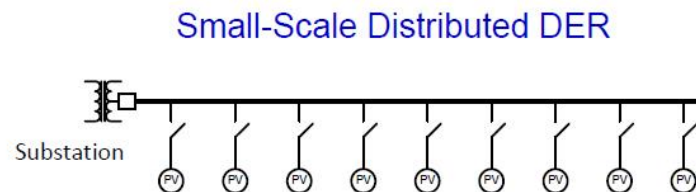
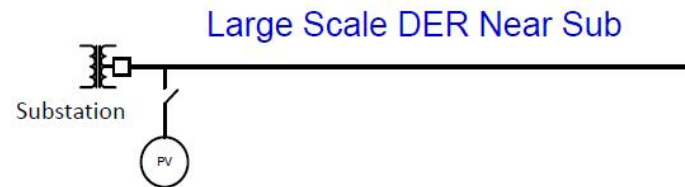
Integration capacity is not a single value, but a range of values, it varies with level of granularity, and it varies at location and time.

- How to define hosting capacity?
 - Hosting capacity is the amount of DER that can be accommodated in a system without any needs for upgrade.
 - Distribution system level DER integration is constrained by thermal loads, power quality and protection schemes
 - Does integration capacity need to be categorized and have sub-levels of definitions based on different types of types of DER?
- How do we think about hosting capacity as a function of time?
 - Current data can determine capacity in a static sense today, which may be a starting point but not an end goal.
- How does hosting capacity fit with regards to optimization of the overall system?
 - It uncovers opportunities of growth by showing areas of sufficient existing capacity and areas of necessary upgrade
 - Can we determine the avoided costs for utilities and for customers?
 - How can we use hosting capacity in a way that relates to promoting a node-friendly grid?
 - You could have a capacity issue that storage could take care of without any upgrades.

Streamlined Hosting Capacity Method

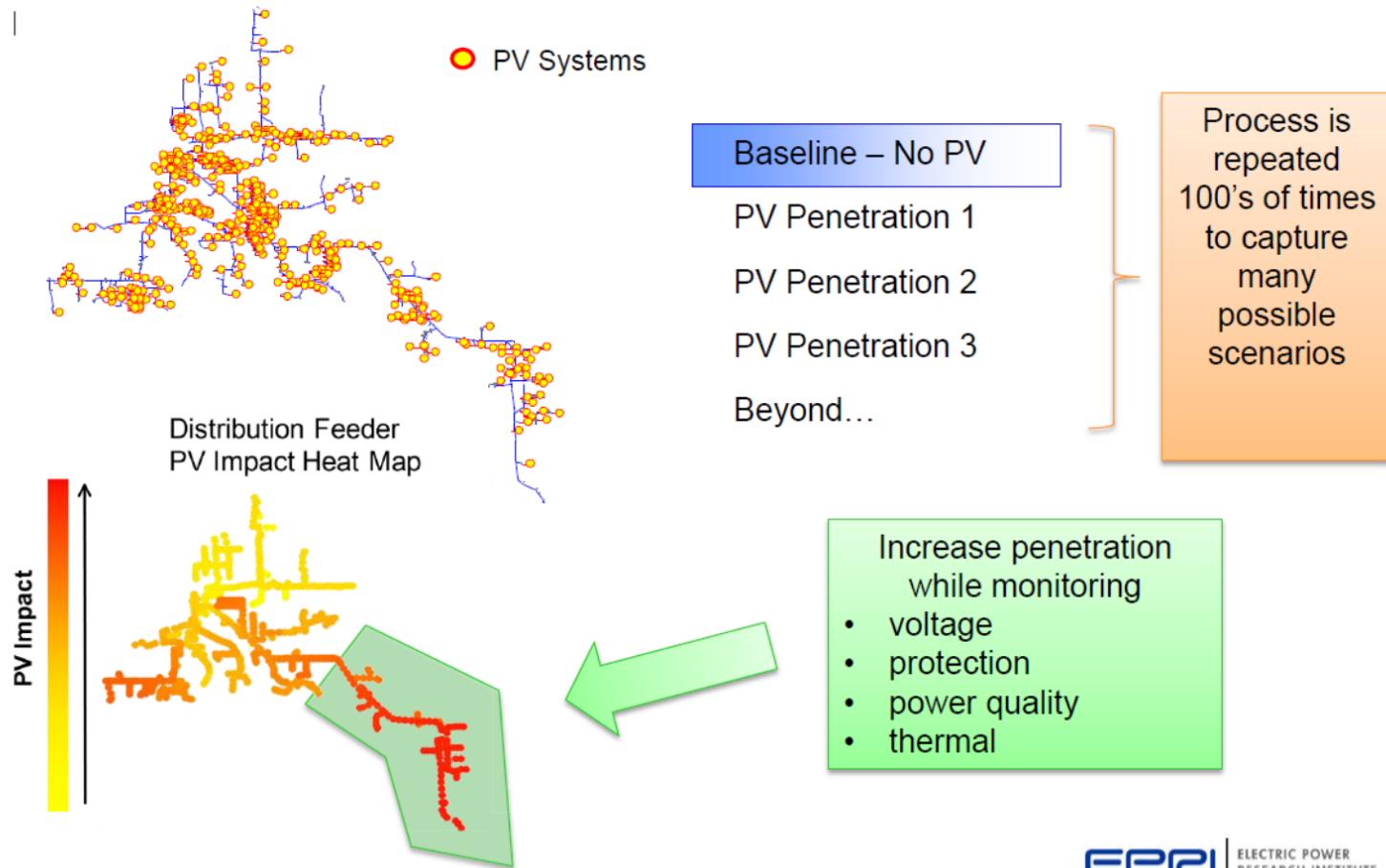
Key Factors that Impact Hosting Capacity

- Size of DER
- **Location** of DER
- Feeder characteristics
- Electrical proximity to other DER
- DER control (e.g, smart inverters)



Streamlined Hosting Capacity Method

Detailed Hosting Capacity: A Brief Primer



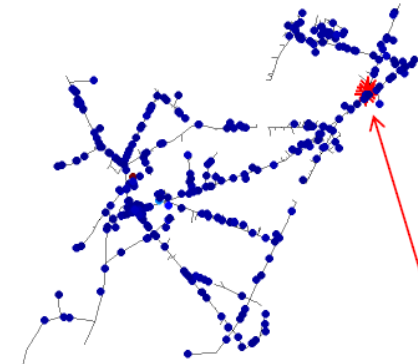
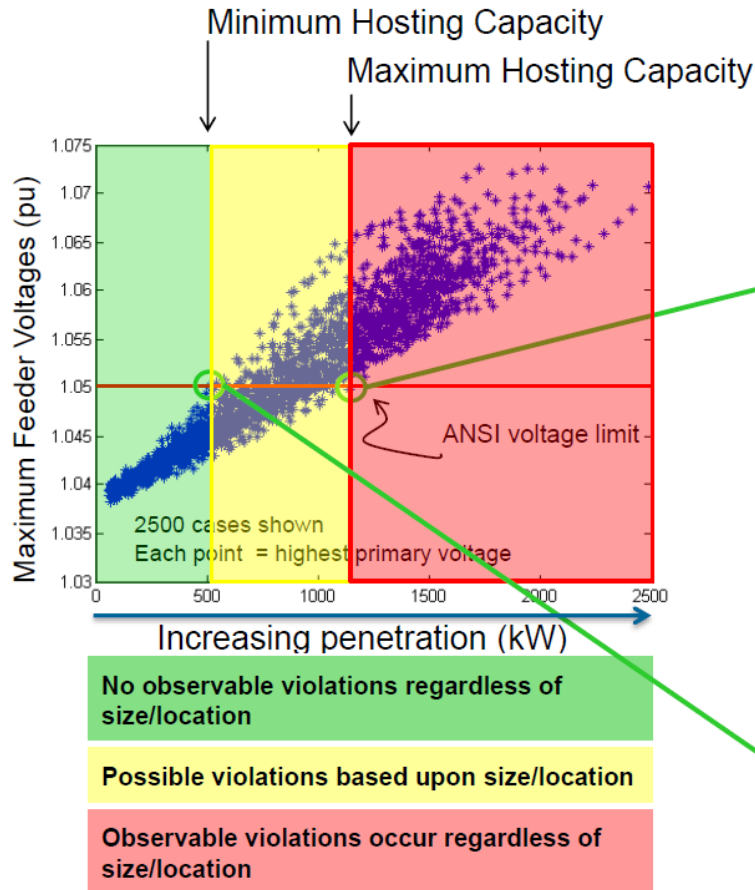
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Streamlined Hosting Capacity Method

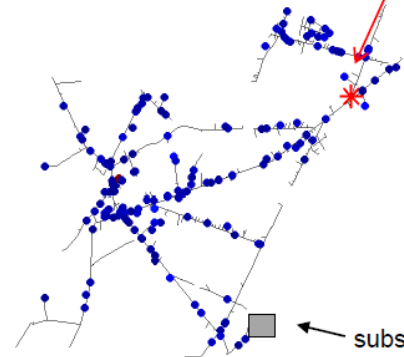
Hosting Capacity

Overvoltage Results Shown for Sample Feeder



Most Optimal Deployment

Voltage violation



Least Optimal Deployment

Streamlined Hosting Capacity Method

Distribution Systems are Unique Sample Hosting Capacity Results in California



- Distribution feeders are designed to reliably serve ALL customers in least-cost manner
- Each distribution feeder is therefore unique
 - Geographic area
 - Number of customers
 - Electrical characteristics (voltage class, regulation, protection, etc)
- Each have a unique hosting capacity for PV

*Results from CPUC/CSI RD&D3 project - "Alternative Screening Methods"
<http://www.calsolarresearch.org/funded-projects/88-screening-distribution-feeders-alternatives-to-the-15-rule>

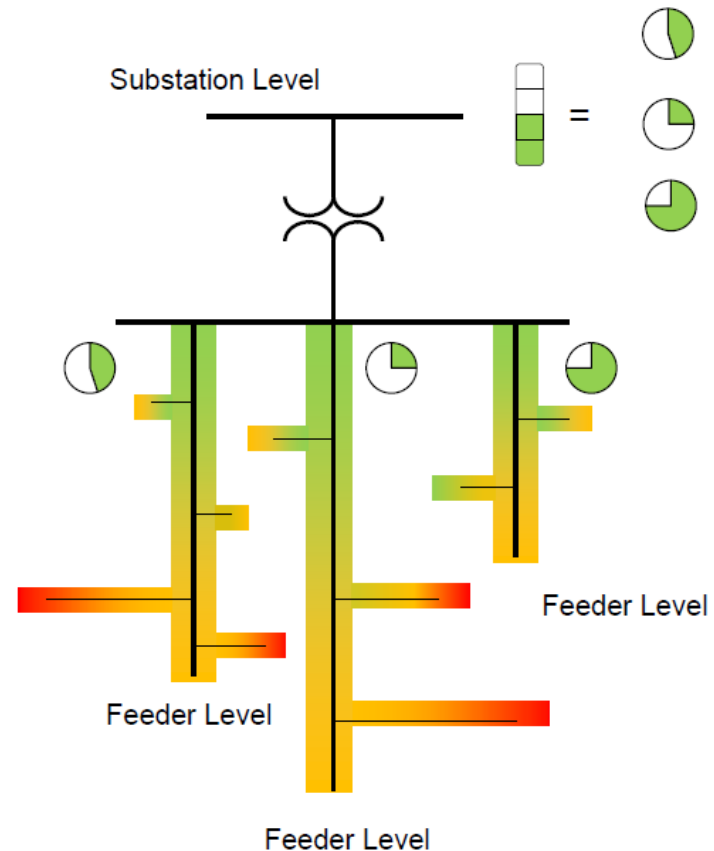
Streamlined Hosting Capacity Method

Distribution Method Requirements

Granular	<ul style="list-style-type: none">• Capture unique feeder-specific responses
Repeatable	<ul style="list-style-type: none">• Across any and all distribution feeders
Scalable	<ul style="list-style-type: none">• Throughout entire distribution system for aggregation and system-wide assessment
Transparent	<ul style="list-style-type: none">• Clear and open methods for analysis
Proven	<ul style="list-style-type: none">• Validated techniques for system performance assessments
Available	<ul style="list-style-type: none">• Utilize readily available utility data and tools (can vary from utility to utility, feeder to feeder)

Streamlined Hosting Capacity Method

- Considers unique response at the individual feeder level
- Calculated based on utility-standard load flow calculations
 - Voltage
 - Fault current
- Output
 - Feeder-level hosting capacity
 - Locational impacts assessment



Details to be published Dec 2014

Streamlined Methods for Determining Feeder Hosting Capacity for PV. EPRI, Palo Alto, CA: 2014.

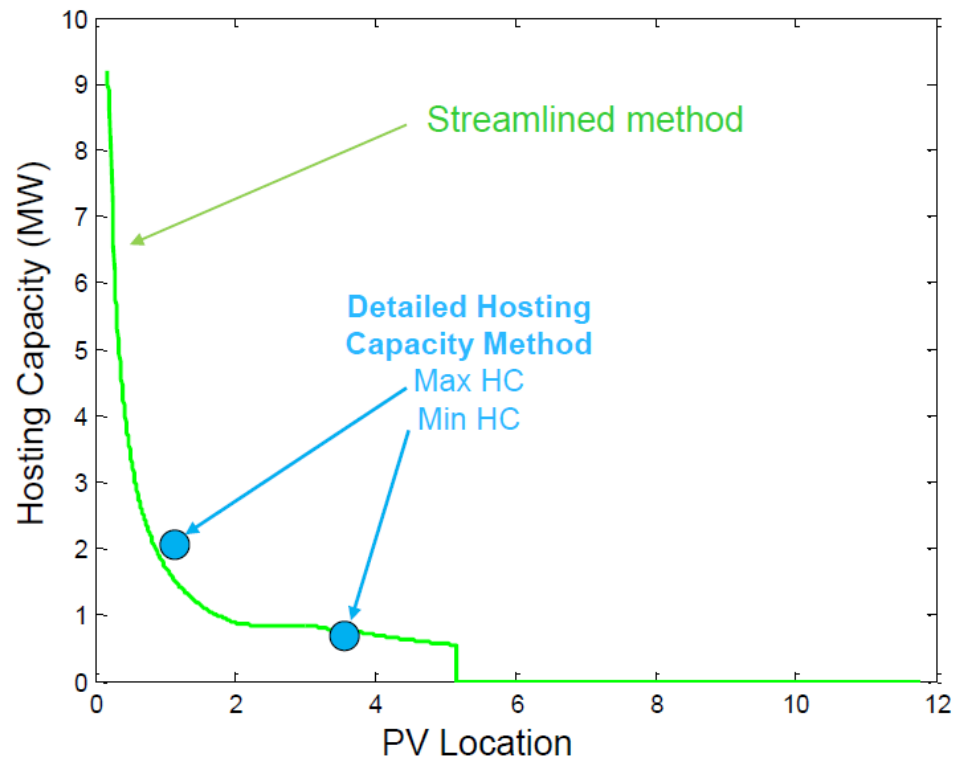
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Streamlined Hosting Capacity Method

Utility-Scale PV Example

- Hosting capacity due to single large DER
 - No diversity in DER location
 - Three-phase locations only
- Similar accuracy comparing small, distributed DER
 - Assumes DER locational diversity

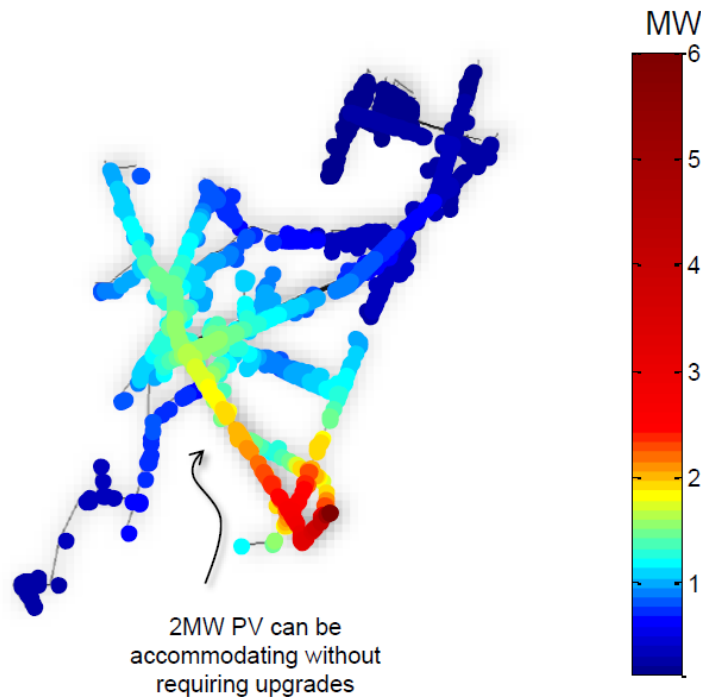
Utility Scale PV Hosting Capacity



Streamlined Hosting Capacity Method

Example Screenshot from Streamlined Hosting Capacity Method

Example: Optimal amount of PV that can be accommodated w/o requiring grid upgrades

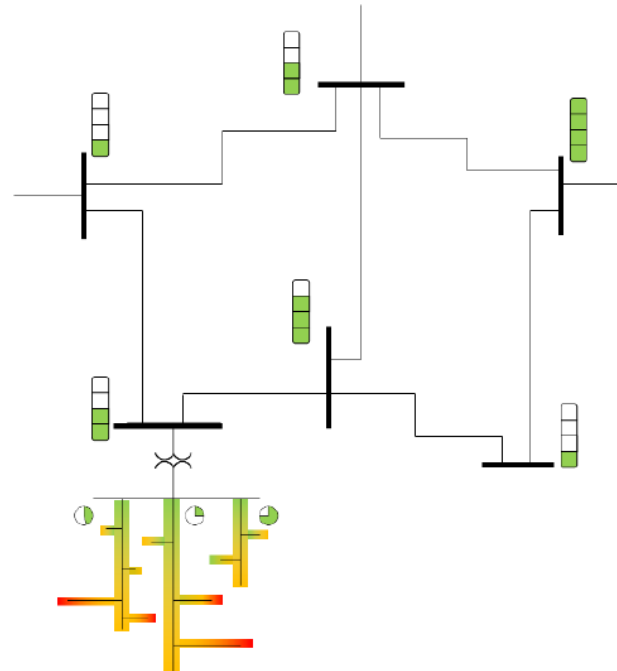


Streamlined Hosting Capacity Method

Assessing DER Across All Distribution

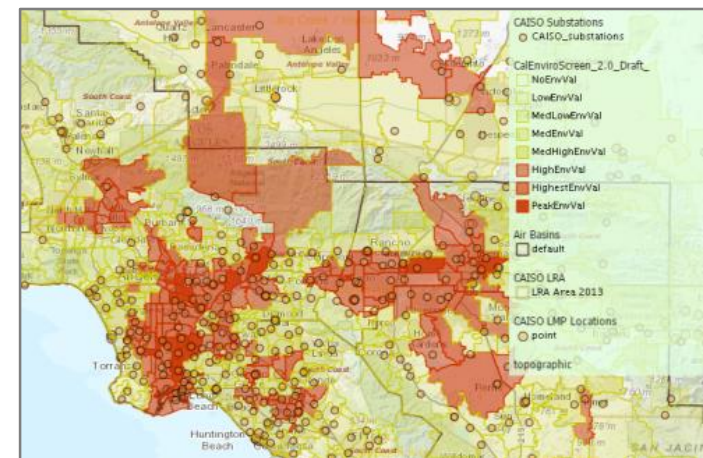
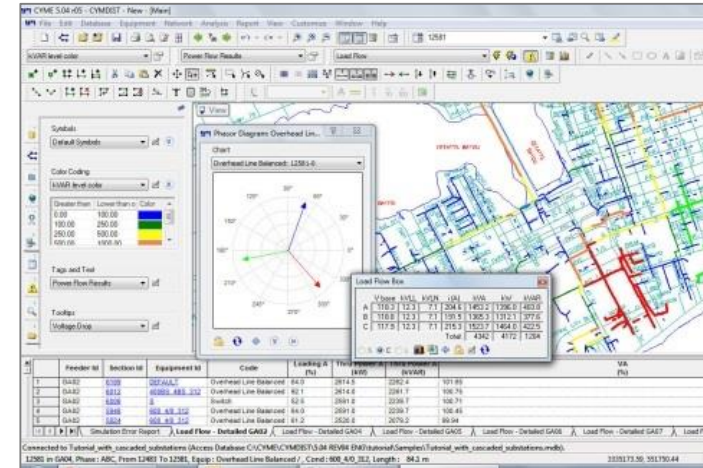
- By streamlining the analysis method, one can:
 - Capture individual feeder responses
 - Aggregate up to substation level
 - Apply throughout distribution systems
 - Repeat analysis as system changes (automated)

System-Wide Assessment
Capturing Feeder-Specific Results



MTS Recommendation

- Conduct integration capacity analysis annually in conjunction with distribution planning
- Analysis will evaluate each distribution feeder, but may use simplified techniques to start
- Results will be published online via a geospatial map such as a modified version of the existing California RAM maps
- First Integration capacity analysis should be done as part of the IOU DRP filing by July 2015 to establish baseline.





Locational Benefits Methods

Locational Benefits Discussion Topics

- Benefits to Bulk Power System
 - How can economic value be attached to other Bulk Power System benefits beyond just power generation metrics?
 - Does system reliability have a usable metric? (i.e. volt var)
 - Does system capacity provide as a usable economic metric? (i.e. avoided costs to infrastructure projects)
 - Can we quantify available capacity by determining the cost minimization to plugging in PV?
- Benefits to Distribution Grid
 - How can incremental value be accounted for as adoption continues?
 - How will the incremental value account for the varying location of adoption with respect to utility incentives for optimal location?
 - How can the benefits from distributed generation be distinguished from energy efficiency at the distribution level?
 - Do we treat metered and non-metered customers differently regarding their impact on the distribution grid?
- Benefits to the environment
 - How can GHG and local area emissions be valued systematically across varying geographies?
- Is value maximization the same as cost minimization?

Avoided Cost/Benefits Studies Reviewed

- E3 – Net Benefits of NEM in California (2013)
- Rocky Mountain Institute – A Review of Solar PV benefit and Cost Studies, 2nd Edition (2014)
- Integral Analytics – Distributed Marginal Price (2014)
- Brattle – Value of Distributed Electricity Storage in Texas (Nov 2014)
- PG&E – Distribution Planning and Investment and Distributed Generation – 2014 GRC Testimony – Appendix C (2013)
- New York – Benefits and Costs (Nov 2014)
- Regulatory Assistance Project – US Experience with Efficiency as a Transmission and Distribution Resource (2012)
- Regulatory Assistance Project – Big Changes Ahead: Impacts of a Changing Utility Environment (2014)
- Regulatory Assistance Project - Designing Distributed Generation Tariffs Well (2014)

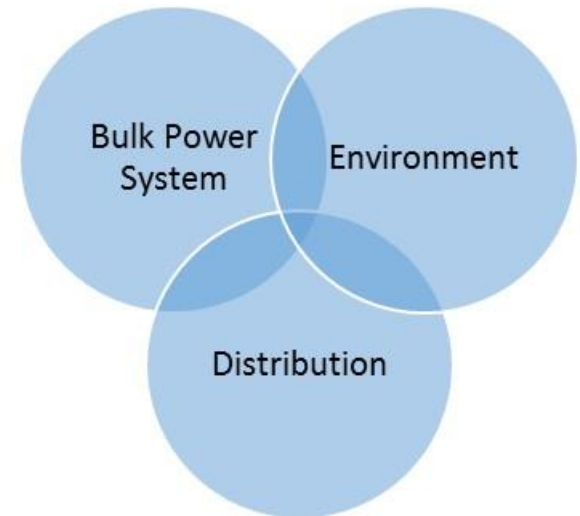
Optimal Location

What are the attributes of locational benefits?

- How do we model how effective each benefit of DER is?
- How do we look at this over time to account for dynamic, flexible benefits rather than static benefits?
- Should the geographic area be constrained locally or relaxed to allow for system wide benefits?

“Benefits” may accrue in several places

- Distribution level benefits: Deferred/Avoided Capital Investment, Power Quality (Volt/Var & harmonics), Asset Utilization
- Bulk power systems benefits: Deliverability, Resource Adequacy, Voltage & Frequency support, Deferred/Avoided Capital Investment, Reduced Losses
- Environmental benefits: GHG reduction, air quality, environmental justice



Optimal Analysis

Optimal analysis based on **cost minimization** of:

- **Planning objectives**

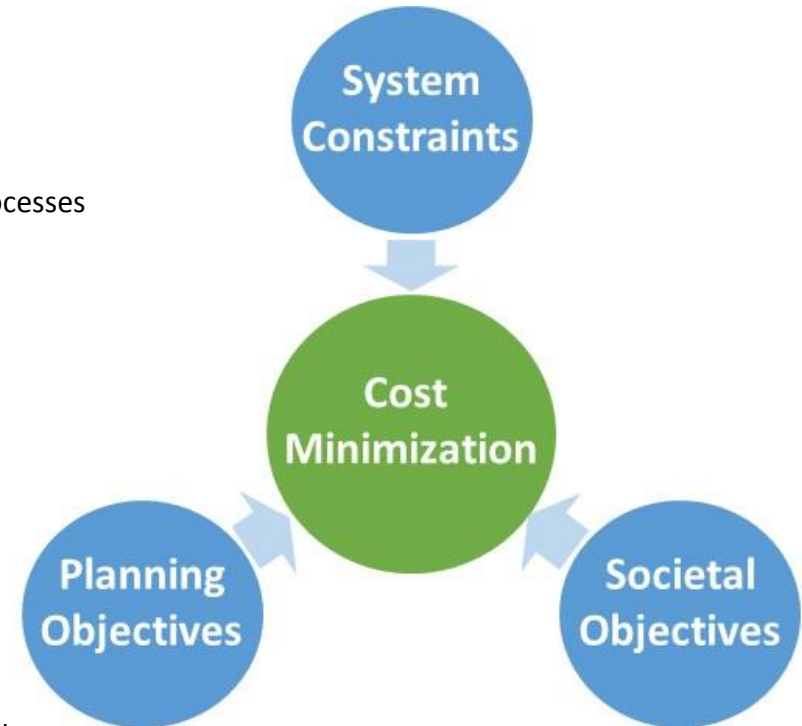
- Reliability
- Environmental
- Policy goals
- Safety
- Load serving capacity
- Asset utilization
- Affordability and cost objectives
- Resiliency and cyber security
- Customer choice
- Streamlined interconnection processes

- **Societal objectives**

- Environmental
- GHG and local area emissions
- Water-energy nexus
- Environmental Justice
- Low income access to reliable power
- Resiliency impacts
- Ease of access
- Job Creation
- Transportation electrification
- Regulatory certainty

- **System Constraints**

- Thermal Limits
- Existing system capacity
- Operating flexibility
- Assets and their depreciation/age
- Institutional constraints
- Technology constraints
- System stability
- Limits of steady-state analysis
- Inability to account for uncertainty
- Protection
- Power Quality (voltage, etc)



Location Benefits

- Values fall into two basic benefit monetization dimensions:
 - Avoided Costs that can be monetized via bulk power market, transmission & distribution cost avoidance
 - Societal benefits that accrue externally and may not be easily monetizable
- Implication: should societal benefits be included in locational benefits analysis?
 - If so, how?
 - What would be needed?

Avoided Costs	Societal Benefits
<i>Wholesale Market & Transmission</i>	<i>Environmental</i>
<i>Distribution</i>	<i>Customer & Other</i>

Locational Benefits Discussion

- MTS WG held several meetings to discuss both avoided cost value components and benefits to environment, customers and society.
- Discussion began with review of existing California avoided cost methods
- Identified gaps in existing methods as related to distribution both in terms of discrete value components and locational granularity
 - Existing methodology was based on system level values, including for a few distribution related components
- WG developed a mutually exclusive and comprehensively exhaustive list of value components to consider for DRP analysis.
- The following slides highlight the WG discussion and results.

CPUC Avoided Cost Framework – Background

- Framework developed by Energy and Environmental Economics (E3) and adopted by the CPUC
- Originally adopted to evaluate cost-effectiveness of energy efficiency by the CPUC in 2004 (Rulemaking 04-04-025)
- Subsequently, a Distributed Generation Cost-Effectiveness Framework was adopted by the Commission (D. 09-08-026)
- Demand Response Cost-Effectiveness Framework was adopted in 2010
- Periodic updates on all three frameworks since 2010
- Most recent methodology described in October 2013 study “California Net Energy Metering Ratepayer Impacts Evaluation”

CPUC Avoided Cost Framework – Component Definitions

Component	Description
Generation Energy	Estimate of hourly marginal wholesale value of energy adjusted for losses between the point of the wholesale transaction and the point of delivery
System Capacity	The marginal cost of procuring Resource Adequacy resources in the near term. In the longer term, the additional payments (above energy and ancillary service market revenues) that a generation owner would require to build new generation capacity to meet system peak loads
Ancillary Services	The marginal cost of providing system operations and reserves for electricity grid reliability
T&D Capacity	The costs of expanding transmission and distribution capacity to meet customer peak loads
CO2 Emissions	The cost of carbon dioxide emissions (CO2) associated with the marginal generating resource
Avoided RPS	The cost reductions from being able to procure a lesser amount of renewable resources while meeting the Renewable Portfolio Standard (percentage of retail electricity usage).

Methodology for Avoided Cost Component Forecasts

Component	Basis of Annual Forecast	Basis of Hourly Shape
Generation Energy	Forward heat rate projections from 2010 CPUC Long Term Procurement Plan and monthly fuel cost projections	Historical hourly day-ahead market price shapes from MRTU OASIS aligned to a typical meteorological year based on daily system loads
System Capacity	Lower of the residual capacity value a new simple-cycle combustion turbine or combined cycle gas turbine	Hourly allocation factors calculated as a proxy for LOLP based on system loads
Ancillary Services	Percentage of generation energy value	Directly linked with energy shape
T&D Capacity	Marginal transmission and distribution costs from utility ratemaking filings.	Hourly allocation factors calculated using hourly TMY temperature data as a proxy for local area load
Environment	CARB 2013 auction results; 2011 Market Price Referent (MPR) ¹⁹	Directly linked with energy shape with bounds on the maximum and minimum hourly value
Avoided RPS	Cost of a marginal renewable resource less the energy and capacity value associated with that resource	Flat across all hours

DER Value Components (1/2)

Objective is to define a mutually exclusive and collectively exhaustive (MECE) list irrespective of whether these could be valued or monetized today, or if the value is part of CA utility revenue requirements. Value components reflect NEM 2.0^A and MTS discussion on potential DER value for Customers, Society, Bulk Power system & Distribution with a focus on locational value.

	Value Component	Definition
Wholesale	WECC Bulk Power System Benefits	Regional BPS benefits not reflected in System Energy Price or LMP
	CA System Energy Price (NEM 2.0)	Estimate of CA marginal wholesale system-wide value of energy
	Wholesale Energy	Reduced quantity of energy produced based on net load
	Resource Adequacy (NEM 2.0 modified)	Reduction in capacity required to meet Local RA and/or System RA reflecting changes in net load and/or local generation
	Flexible Capacity	Reduced need for resources for system balancing
	Wholesale Ancillary Services (NEM 2.0)	Reduced system operational requirements for electricity grid reliability including all existing and future CAISO ancillary services
	RPS Generation & Interconnection Costs (NEM 2.0)	Reduced RPS energy prices, integration costs, quantities of energy & capacity
	Transmission Capacity	Reduced need for system & local area transmission capacity
	Generation/DER Deliverability	Increased ability for generation and DER to deliver energy and other services into the wholesale market
	Transmission Congestion + Losses (NEM 2.0 modified)	Avoided locational transmission losses and congestion as determined by the difference between system marginal price and LMP nodal prices
	Wholesale Market Charges	LSE specific reduced wholesale market & transmission access charges

A. NEM 2.0 values drawn from E3 identified avoided cost components on slide 33 in “Overview of Public Tool to Evaluate Successor Tariff/Contract Options”, Dec. 16, 2014

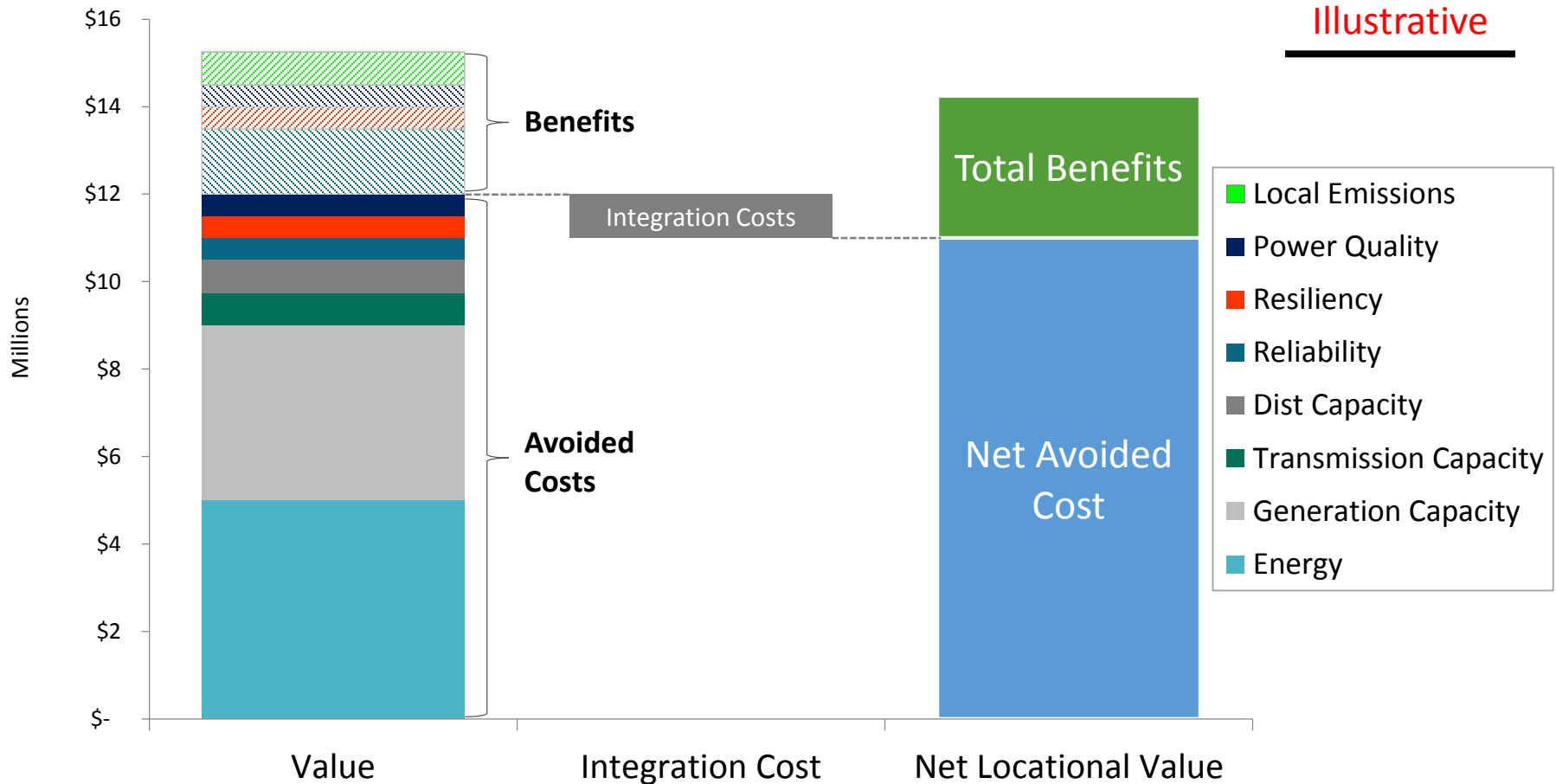
DER Value Components (2/2)

	Value Component	Definition
Distribution	Subtransmission, Substation & Feeder Capacity (NEM 2.0 modified)	Reduced need for local distribution system upgrades
	Distribution Losses (NEM 2.0)	Value of energy due to losses between wholesale transaction and distribution points of delivery
	Distribution Steady-state Voltage	Improved steady-state (generally >60 sec) voltage, voltage limit violation relief, reduced voltage variability, compensating reactive power
	Distribution Power Quality	Improved transient voltage and power quality, including momentary outages, voltage sags, surges, and harmonic compensation
	Distribution Reliability + Resiliency+ Security	Reduced frequency and duration of outages & ability to withstand and recover from external natural, physical and cyber threats
	Distribution Safety	Improved public safety and reduced potential for property damage
Customer & Societal	Customer Choice	Customer & societal value from robust market for customer alternatives
	CO2 Emissions (NEM 2.0 modified)	Reductions in federal and/or state carbon dioxide emissions (CO2) based on cap-and-trade allowance revenue or cost savings or compliance costs
	Criteria Pollutants	Reduction in local emissions in specific census tracts utilizing tools like CalEnviroScreen. Reduction in health costs associated with GHG emissions
	Energy Security	Reduced risks derived from greater supply diversity
	Water Use	Synergies between DER and water management (electric-water nexus)
	Land Use	Environmental benefits & avoided property value decreases from DER deployment instead of large generation projects
	Economic Impact	State and/ or local net economic impact (e.g., jobs, investment, GDP, tax income)

Value Analysis: Avoided Costs and Benefits

Locational Value: Avoided Costs and Benefits

Illustrative



Note: Analysis excludes some avoided costs/benefits that do not have a locational dimension. Therefore, analysis is not intended to estimate full stack of avoided costs and benefits associated with DER

DRP Methods & Analysis Discussion

- MTS WG considered the methods to determine the locational value for each component
- Discussion involved consideration of:
 - Existing CA methods, if applicable
 - Proposed methods by researchers (EPRI, RMI, others)
 - Maturity of methods (research stage thru regulatory acceptance)
 - Current power engineering and economic modeling capabilities
 - Required granularity of information and availability
 - Information required from other CA state-wide planning and timing (this led to need to identify DPP alignment)
- The discussions recognized that it was practical to stage the inclusion of the DER value components into the DRP analyses over time
- Proposed Walk-Run-Jog stages for implementation
 - This approach illustrated on next slide assumed that CA had already been thru a “Crawl” stage involving the initial issues of DER integration involving Rule 21 interconnection changes, smart inverter requirements, and initial integration of all other forms of DER (DR, EV, storage, energy efficiency) along with several early demonstrations

DRP Methodology Discussion

- The following slides were used in the working group discussions to further articulate the attributes and methods for each value component.
- These slides are working drafts that illustrate the thinking that led to the recommendations for the initial DRPs
- Discussion on the advanced methods as may be included in later years was not completed as the focus shifted to the near term needs to support the July 2015 requirements.
- These slides may have different descriptions of the value components than were adopted in final form as described on slides 54 & 55.
- As such, these slides should be considered working drafts for illustration only.

DER Values & Methods (1 of 3)

Working Draft

Value Category	Definition	Value Granularity		Utility Avoided Cost Type		Non-Utility Benefits		Possible Today (Current Method and/or Info Source)	Desired (Proposed Method and/or Info Source)	Monetization (CPUC, CAISO, FERC, Other)	Comments
		Local	System	CapEx	OpEx	Societal Benefit (Public Externality)	Customer Benefit (Private)				
Distribution Losses	Estimate of value of additional marginal wholesale value of energy due to losses between the point of the wholesale transaction and the point of delivery	✓			✓			NEM 2.0 (E3) Methodology	Location/Line section specific loss reduction estimated through 1. CVR; 2. power flow modeling; or 3. locally metered loss reduction	CPUC Authorized	
Subtransmission Capacity	Reduced need for local subtransmission capacity expansion to meet customer peak loads	✓		✓	✓			Local subtransmission analysis of incremental capacity requirements	Modified planning criteria from what is currently used in the planning process that reflects the deferral value of capital.	CPUC Authorized	
Distribution Capacity (Local Substation & Feeder)	Reduced need for local distribution capacity expansion to meet customer peak loads	✓		✓	✓			Local distribution analysis of incremental capacity requirements (utility area projections; interconnection applications & studies)	Engineering-economic optimization analysis based on feeder and customer data, plus modified planning criteria from what is currently used in the planning process that reflects the deferral value of capital. This also involves an optimal portfolio analysis is performed to reduce cost and/or timelines to meet policy targets (e.g., EV adoption, Net Zero standards, and various mandates)	CPUC Authorized	Reduced future net operating and capital costs & incremental benefits related to more robust distribution system and efficient operation.
Power Quality	Improved steady state voltage control within standards and reduced transient or momentary under/over voltage and harmonics	✓		✓	✓	✓	✓	Local distribution analysis of incremental power quality requirements (utility area projections; interconnection applications & studies)	Modification to utility capital investment plans for automation and capacitors	CPUC Authorized	
Reliability	Reduced frequency and duration of distribution feeder outages typically measured in SAIDI/SAIFI	✓		✓	✓	✓	✓	DOE Interruption Cost Calculator + Utility Reliability Report	Long term goal to reflect forecasted SAIDI/SAIFI improvements as a result of grid modernization and technology integration	CPUC Authorized	
Resiliency	Improved ability to withstand and recover from external threats, i.e., cyber, catastrophic, cascading)	✓		✓	✓	✓	✓		Long term goal to develop enhanced emergency recovery plans that integrate DER as a reliable resource with utility control.	CPUC Authorized	
Safety	Improved safety as a result of new technology integration	✓			✓	✓	✓		Long term goal to reflect forecasted safety improvements as a result of grid modernization and technology integration	CPUC Authorized	

DER Values & Methods (2 of 3)

Working Draft

Value Category	Definition	Value Granularity		Utility Avoided Cost Type		Non-Utility Benefits		Possible Today (Current Method and/or Info Source)	Desired (Proposed Method and/or Info Source)	Monetization (CPUC, CAISO, FERC, Other)	Comments
		Local	System	CapEx	OpEx	Societal Benefit (Public Externality)	Customer Benefit (Private)				
Customer Choice	Customer's ability to choose alternative reliability enhancement and supply options. Societal value associated with robust		✓			✓	✓				
CO2 Emissions	The cap-and-trade allowance revenue or cost savings due to reductions in carbon dioxide emissions (CO2)	✓			✓	✓				CPUC Authorized	
Criteria Pollutants	Avoided permit costs, Cap Ex (emission controls), OpEx (GHG market, emission control operation)	✓	✓			✓		CARB; CEC Cost of Generation model; E3 GHG Calculator; NREL Emissions Health Calculator.	Marginal emission reduction value; Inclusion of lifecycle emissions costs		CARB air quality permit and GHG markets included in energy costs. Note: this isn't part of any utility
Health Benefits	Public health costs; business health costs, avoided lost work days	✓	✓			✓		NREL Emissions Health Calculator			Note: this isn't part of any utility funding authorization
Water Use	Reduced water consumption by power generation cooling	✓	✓			✓		DOE estimates based on avoided generation and fuel type			Note: this isn't part of any utility funding authorization
Land Use	Permit market costs; real estate value	✓				✓		Estimates based on avoided capacity, plus fuel extraction & delivery	Standard marginal values specific to location		Note: this isn't part of any utility funding authorization
Improved Energy & Water Security	Reduced risks derived from greater supply diversity, transportation electrification and synergies with water		✓			✓					Note: this isn't part of any utility funding authorization
Jobs	Direct, Indirect, and Induced employment (increased economic activity, decreased unemployment related costs)	✓	✓			✓		NREL Jobs and Economic Development Indicator (JEDI) input/output model [State	JEDI adjustments for local specificity		Note: this isn't part of any utility funding authorization
Economic Impact	State or local net economic impact (investment, income, GDP, public revenue [tax & fee income])	✓	✓			✓		NREL Jobs and Economic Development Indicator (JEDI) model; Berkeley Energy and	JEDI adjustments for local specificity		Note: this isn't part of any utility funding authorization

Blue = NEM 2.0 Identified Values

Yellow = MTS identified value

DER Values & Methods (3 of 3)

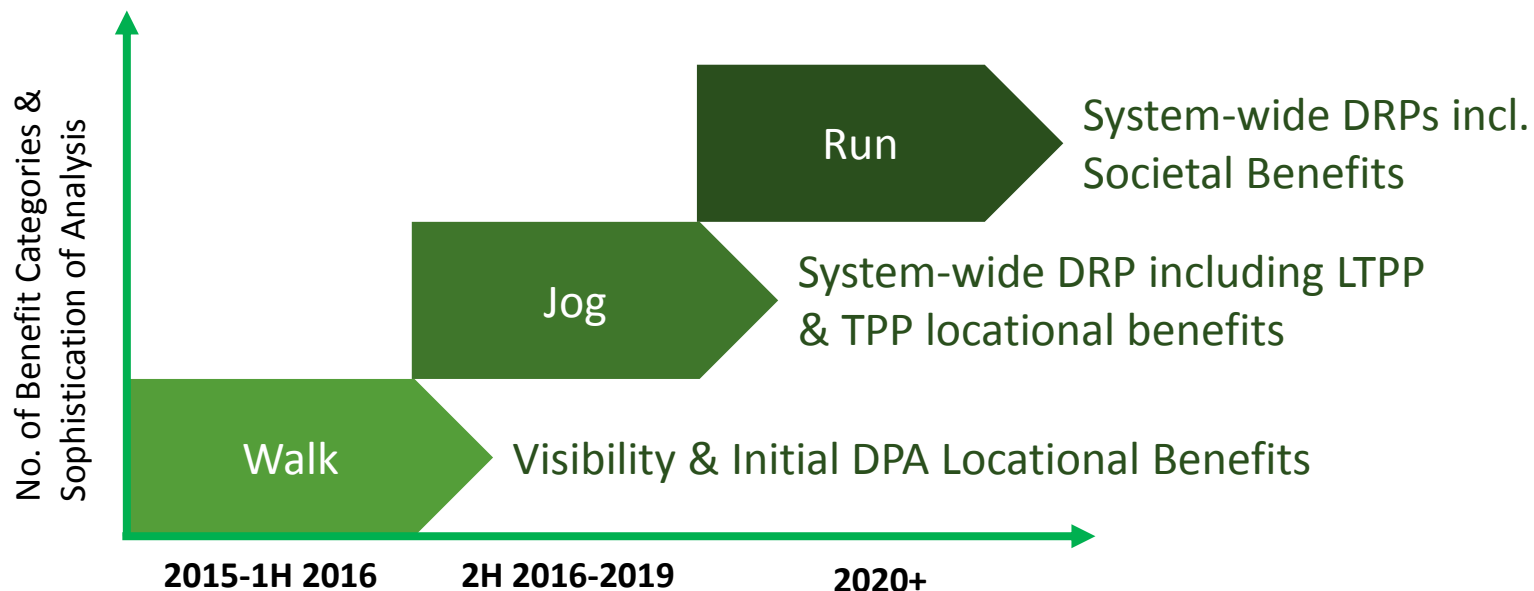
Working Draft

Value Category	Definition	Value Granularity		Utility Avoided Cost Type		Non-Utility Benefits		Possible Today (Current Method and/or Info Source)	Desired (Proposed Method and/or Info Source)	Monetization (CPUC, CAISO, FERC, Other)	Comments
		Local	System	CapEx	OpEx	Societal Benefit (Public Externality)	Customer Benefit (Private)				
WECC Regional System	WECC Regional bulk power system benefits not reflected in System Energy Price or LMP		✓		✓	✓					Value associated with CA DER participation in or impact on WECC regional markets
Thermal Generation (System Energy Price)	Estimate of marginal wholesale system wide value of energy (valued at \$0/MWh when renewables are on the margin)		✓		✓			NEM 2.0 (E3) Methodology		CPUC Authorized	
Locational Transmission Losses & Congestion	Avoided locational transmission losses and congestion	✓			✓			System energy price forecast from NEM 2.0 minus specific LMP nodal price estimate		CAISO	
Ancillary Services	Reduced system operations and reserves (or costs) required for electricity grid reliability		✓		✓			NEM 2.0 (E3) Methodology		CAISO	
RPS Generation & Integration Costs	Cost reductions from being able to procure RPS energy at lower prices, procure a lesser amount of energy and capacity, and reduced costs of integration		✓		✓	✓		NEM 2.0 (E3) Methodology		CPUC Authorized	Ratepayer, and Public Good (RPS targets, reduced emissions, improved economic impact)
System Capacity	The reduced reliability-related cost of maintaining a generator fleet with enough capacity to meet annual peak loads and the planning reserve margin	✓		✓	✓			NEM 2.0 (E3) Methodology		CAISO	
Transmission Access Charges	LSE avoided Transmission Access Charges (subject to FERC tariff change that rebalances costs)		✓				Specific LSE benefit	HV & LV TAC Tables; CAISO (BriefingLong-TermForecastTransmissionAccessCharge), IEPR TAC projections		CAISO TAC Tariff	
Transmission Capacity	Reduced need for system & local area transmission capacity	✓		✓				TPP analysis, & [average] marginal cost of new transmission capacity	Require some modified regional transmission criteria that would be acceptable by NERC standards for reliability. Would require additional study to determine the reliability of counting on DER to meet standards.	FERC	

Blue = NEM 2.0 Identified Values
Yellow = MTS identified value

Implementation of DRP Location Benefits Analysis

Stages reflect that certain value components can be evaluated today using accepted methods and tools, and are tangibly linked to locational avoided costs – others require integrated analysis with TPP & LTPP or are not as mature in terms of value assessment



Concept was adopted by CPUC in its February 2015 final guidance

Walk Stage: Initial DRP (July 2015 filing)

- Focus on development of recommendation for initial scope of DRP including methodologies
- The following slides summarize the discussion and recommendations before the CPUC Final Guidance and afterward in support of the IOU's development of their filings.
- These value components and valuation methodologies will be used to define specific services, related performance requirements and sourcing approaches as may be incorporated in the required DRP demonstrations
- It is recognized that the primary values under CPUC jurisdiction are associated with utility avoided costs. As such, sourcing DER services will involve one of the following general methods, pricing (rate designs), programs (EE & DR), or procurements (e.g., RFO/RFPs)
- The discussion of services and sourcing structures will be further discussed by the MTS in Q2 2015.

Objectives for July 2015 Optimal Location Analysis

- **What does this analysis intend to accomplish?**
 - Identify optimal locations for DER deployment
 - Consider *mutually exclusive, collectively exhaustive* locational avoided costs and benefits
 - Illustrate a quantitative spread in DER locational value by utility planning area/substation
- **What does this analysis NOT intend to accomplish?**
 - Completely replicate the CPUC/RMI/E3 avoided cost methodology
 - Accurately account for the *full* value of DER assets (some value components do not differ by location, and so will not be included in this analysis)
 - Consider only one DER technology type (this analysis is focused on the potential benefits of all/any DER, not a specified technology)
 - Directly inform pricing for any DER tariffs / markets (tariffs and/or markets may be derived from the insights of this analysis, but this analysis is not a tariff pricing exercise).

Final CPUC Guidance on Optimal Location Benefit Analysis

CPUC Adopted Walk-Jog-Run Approach and Adapted Initial Value Components

CPUC Initial DRP Requirements:

- IOU Unified Locational Net Benefits methodology
- Based on E3 Cost-Effectiveness Calculator, but enhanced to include following location-specific values (minimum):

#	<u>Minimum Value Components to include in Locational Net Benefit Methodology</u>
1	Avoided Sub-Transmission, Substation and Feeder Capital and Operating Expenditures
2	Avoided Distribution Voltage and Power Quality Capital and Operating Expenditures
3	Avoided Distribution Reliability and Resiliency Capital and Operating Expenditures
4	Avoided Transmission Capital and Operating Expenditures
5	Avoided Flexible Resource Adequacy (RA) Procurement
6	Avoided Renewables Integration Costs
7	Any societal avoided costs which can be clearly linked to the deployment of DERs
8	Any avoided public safety costs which can be clearly linked to the deployment of DERs

MTS Identified DER Value Components (1/2)

For reference, yellow highlighted value components relate MTS defined values to CPUC Final Guidance for initial DRPs

Societal & Environmental value components left to IOUs to identify locational linkage

	Value Component	Definition
Wholesale	WECC Bulk Power System Benefits	Regional BPS benefits not reflected in System Energy Price or LMP
	CA System Energy Price	Estimate of CA marginal wholesale system-wide value of energy
	Wholesale Energy	Reduced quantity of energy produced based on net load
	Resource Adequacy	Reduction in capacity required to meet Local RA and/or System RA reflecting changes in net load and/or local generation
	Flexible Capacity	Reduced need for resources for system balancing
	Wholesale Ancillary Services	Reduced system operational requirements for electricity grid reliability including all existing and future CAISO ancillary services
	RPS Generation & Interconnection Costs	Reduced RPS energy prices, integration costs, quantities of energy & capacity
	Transmission Capacity	Reduced need for system & local area transmission capacity
	Generation/DER Deliverability	Increased ability for generation and DER to deliver energy and other services into the wholesale market
	Transmission Congestion + Losses	Avoided locational transmission losses and congestion as determined by the difference between system marginal price and LMP nodal prices
	Wholesale Market Charges	LSE specific reduced wholesale market & transmission access charges

MTS Identified DER Value Components (2/2)

	Value Component	Definition
Distribution	Subtransmission, Substation & Feeder Capacity	Reduced need for local distribution system upgrades
	Distribution Losses	Value of energy due to losses between wholesale transaction and distribution points of delivery
	Distribution Steady-state Voltage	Improved steady-state (generally >60 sec) voltage, voltage limit violation relief, reduced voltage variability, compensating reactive power
	Distribution Power Quality	Improved transient voltage and power quality, including momentary outages, voltage sags, surges, and harmonic compensation
	Distribution Reliability + Resiliency+ Security	Reduced frequency and duration of outages & ability to withstand and recover from external natural, physical and cyber threats
	Distribution Safety	Improved public safety and reduced potential for property damage
Customer, Environmental & Societal	Customer Choice	Customer & societal value from robust market for customer alternatives
	CO2 Emissions	Reductions in federal and/or state carbon dioxide emissions (CO2) based on cap-and-trade allowance revenue or cost savings or compliance costs
	Criteria Pollutants	Reduction in local emissions in specific census tracts utilizing tools like CalEnviroScreen. Reduction in health costs associated with GHG emissions
	Energy Security	Reduced risks derived from greater supply diversity
	Water Use	Synergies between DER and water management (electric-water nexus)
	Land Use	Environmental benefits & avoided property value decreases from DER deployment instead of large generation projects
	Economic Impact	State and/ or local net economic impact (e.g., jobs, investment, GDP, tax income)

E3 Cost Effectiveness Methodology

- Utilize E3’s Distributed Energy Resources Avoided Cost Model (DERAC)
- But, Current DERAC model has “system level” values that need to be modified/replaced with relevant locational specific values.

E3 Value Components	System/Local	E3 DERACT Method
Generation Energy	System	Forward market prices based on fixed and variable operating costs of CCGT.
Losses	System	System loss factors
Generation Capacity	System	Residual capacity value for a new simple-cycle combustion turbine
Ancillary Services	System	Percentage of generation energy value
T&D Capacity	System	Marginal system-wide sub-transmission and distribution costs from utility ratemaking filings
Environment	System	Synapse Mid-level carbon forecast developed for use in electricity sector IRPs
Avoided RPS	System	Cost of marginal renewable resource less the energy market and capacity value associated with that resource

Proposed Adaptation of E3 DERACT for Locational Benefits Analysis

	Value Components	E3 DERACT	CPUC Guidance	Recommendation
DERACT Values	Generation Energy	System	N/A	
	Losses	System	N/A	
	Generation Capacity	System	Flexible RA	Use MTS Method in DERACT based on Local Capacity Requirement
	Ancillary Services	System	N/A	
	T&D Capacity	System	Yes, Local	Use MTS Method in DERACT
	Environment	System	Yes, Local	Use MTS Method in DERACT
	Avoided RPS	System	N/A	
Additional Values	Transmission Capacity	None	Yes, Local	Use MTS Method in DERACT
	Dist. Voltage & Power Quality	None	Yes, Local	Use MTS Method in DERACT
	Dist. Reliability, Resiliency & Security	None	Yes, Local	Use MTS Method in DERACT
	Safety	None	Yes, Local	Use MTS Method in DERACT
	Renewable Integration Costs	None	Yes, System	Use MTS Method in DERACT

MTS Initial DRP Recommendations

Initial DRP as defined in CPUC Guidance – this is the Walk Stage

- Utilize E3's DERACT model as starting point, but leverage MTS locational methods in lieu of system values as applicable
 - For example, Local RA will be used for Generation Capacity value
- Generation related integration costs incorporated using interim integration adder adopted by CPUC – System value
- Societal & Public Safety will be included as qualitative factors until quantitative data is available.
- Review and compare T&D deferral benefit calculations among the IOUs
- For all categories, DERs may increase cost (e.g., integration systems cost). Net Benefit for specific technologies will account for any increased costs.

Final Commission Guidance and MTS WG Recommendations

	Final Commission Guidance (Minimum Value Components in LNB Methodology)	Reference MTS Value Component/s	MTS DER Value Component Definition	MTS Value Calculation Approach
Wholesale	Avoided Flexible Resource Adequacy (RA) Procurement	Local Area Resource Adequacy & Flexible Resource Adequacy	Reduction in capacity required to meet Local RA and/or System RA reflecting changes in net load and/or local generation	Use latest CAISO local capacity requirements to identify incremental capacity needs beyond current generation and identify deficient sub-areas, where the Benefit/Avoided cost is the value of deferred Local Capacity or transmission
	Avoided Transmission Capital and Operating Expenditures	Transmission Capacity	Reduced need for system & local area transmission capacity	Use existing CAISO TPP by substation and/or perform load forecasting versus capacity analysis to forecast needed capacity upgrades where Benefit/Avoided cost is the value of deferring transmission capacity work
	<i>{Final Commission Guidance does not explicitly include transmission congestion + losses}</i>	Transmission Congestion + Losses	Avoided locational transmission losses and congestion as determined by the difference between system marginal price and LMP nodal prices	Use estimate in ranking substations as practical
Distribution	Avoided Sub-Transmission, Substation and Feeder Capital and Operating Expenditures	Sub-transmission, Substation and Feeder Capacity	Reduced need for local distribution system upgrades	Use existing utility capacity 10-year plans by substation and/or perform load forecasting versus capacity analysis for forecast needed capacity upgrades, where the Benefit/Avoided cost is the value of deferring capacity work
	Avoided Distribution Voltage and Power Quality Capital and Operating Expenditures	Distribution Power Quality + Reactive Power	Improved transient & steady-state voltage, reactive power optimization and harmonics	Use existing utility power quality investment plan by substation or perform load forecasting versus voltage/power quality analysis to forecast needed voltage/power quality upgrades where the Benefit/Avoided cost is the value of deferring voltage/power quality work
	Avoided Distribution Reliability and Resiliency Capital and Operating Expenditures	Distribution Reliability + Resiliency	Avoidable costs incurred to proactively prevent/mitigate routine outages (reliability) and major outages (resiliency). Avoidable costs incurred in responding to routine outages (reliability) and major outages (resiliency), where Distribution Resiliency costs are defined as spending needed to meet reliability expectations that are above/beyond distribution planning criteria to address major outage events	Use existing utility reliability investment plan by substation or allocate system wide reliability investment plan according to reliability statistics (i.e. SAIDI, CAIDI, SAIFI) by substation/local area, where Benefit/Avoided cost is the value of deferring reliability/resiliency work
	Any avoided public safety costs which can be clearly linked to the deployment of DERs	Distribution Safety	Improved public safety and reduced potential for property damage	Until more data is available in this area, qualitatively describe the Public Safety Benefits. In some cases DER could potentially increase costs and hazards for safety related items
	Avoided Renewables Integration Costs	<i>{DER integration is currently determined at a system level and is not location specific}</i>	Avoidable incremental costs to integrate renewables onto electric system	Current cost calculation is an interim method for calculating renewable integration costs at a system level, which is to be replaced in 2015. Utilities to coordinate efforts with development of the updated RPS Calculator and Renewables Integration Charge to factor in locational specific values
Societal	Any societal avoided costs which can be clearly linked to the deployment of DERs	CO2 Emissions	Reductions in federal and/or state CO2 emissions based on cap-and-trade allowance revenue or cost savings or compliance costs	Until more data is available in this area, qualitatively describe the Societal Avoided Costs. Potentially use CalEnviro screening tool. In some cases DERs impose costs on society such as increased taxes for those not participating with DERs

MTS Working Group

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