What’s a Watt Worth

DG Interconnection Collaborative (DGIC)
August 17, 2016

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Pacific Gas and Electric (PG&E), California

Dennis Elsenbeck
Director of Stakeholder and Policy
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Sai Moorty
Principal, Market Design and Development
Electric Reliability Council of Texas (ERCOT)
Purpose of Today’s Meeting

• Learn how the states of California, New York and Texas have developed novel approaches to valuing Distributed Energy Resources (DER), including solar PV.

• DGIC’s next webinar will
  – Recap the projects being executed under NREL’s utility technical assistance program, and review lessons learned.
  – Discuss the state of distributed generation and how the definition is evolving with the changing grid.
  – DGIC wants to hear from you what the needs are for FY 2017.
Participants are joined in listen-only mode.

Use the Q&A panel to ask questions during the webinar.

To ask a question: Type your question in the Q&A gotowebinar toolbar.

We will have a few minutes of Q&A between each presentation and group discussion at the very end.

The webinar is being recorded and will be posted on the DGIC site:
http://www.nrel.gov/tech_deployment/dgic.html
Agenda (1 ½ hour)

5 mins. Overview of DGIC (Emerson Reiter - NREL)

55 mins. Webinar: What’s a Watt Worth?
   (Each speaker will present for 15 to 20 minutes)

30 mins. Q&A/discussion
DGIC Background and Context

• Supported by U.S. DOE SunShot Initiative
• Formed following a stakeholder workshop in October 2013
• Focused on informational exchange and innovation related to distributed PV interconnection processes and practices
DGIC Framework and Activities

**Area 1: Practices and Protocols**
- Document and understand current practices and approaches
- Identify replicable innovation and consistency

**Area 2: Peer Exchange**
- Data and information exchange amongst stakeholders
- Informational webinar series
- And
- Technical review committee

**Area 3: Technical Assistance**
- Provided via NREL’s Solar Technical Assistance Team (STAT)
- Documenting commonly requested topics, lessons learned, case studies
DGIC and Technical Assistance Resources

• Participate in the Collaborative and shape the discussion by signing up through the DGIC web page

• Find webinar slides and the recording on the DGIC webpage

http://www.nrel.gov/tech_deployment/dgic.html
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Project Lead (DGIC Moderator)
NREL
What’s a Watt Worth

Antonio Alvarez

PG&E
Integrated Planning for DERs Using Locational Net Benefit Analysis (LNBA)

NREL August 17, 2016 Webinar

Antonio Alvarez, Renewable Integration Manager
Agenda

- Introduction
- AB327 distribution resources plan proposal
- Distributed energy resources (DER) optimal locations
- Locational net benefit analysis (LNBA)
- LNBA categories and components
- Integrating DERs in planning processes
A few words about PG&E

Company profile

- Provides natural gas and electric service to 16 million people in northern and central California
- 5.5 million electric accounts
- 70,000-square-mile service area
  Transmission: 18,616 circuit miles
- Distribution: 141,215 circuit miles
- 3,000 Distribution Feeders
AB 327 (2013) added Public Utilities Code Section 769

769. (a) For purposes of this section, “distributed resources” means distributed renewable generation resources, energy efficiency, energy storage, electric vehicles, and demand response technologies.

(b) Not later than July 1, 2015, each electrical corporation shall submit to the commission a distribution resources plan proposal to identify optimal locations for the deployment of distributed resources. Each proposal shall do all of the following:

1. Evaluate locational benefits and costs of distributed resources located on the distribution system. This evaluation shall be 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 the distributed resources provides to the electric grid or costs to ratepayers of the electrical corporation.

2. Propose or identify standard tariffs, contracts, or other mechanisms for the deployment of cost-effective distributed resources that satisfy distribution planning objectives.

3. Propose cost-effective methods of effectively coordinating existing commission-approved programs, incentives, and tariffs to maximize the locational benefits and minimize the incremental costs of distributed resources.

4. Identify any additional utility spending necessary to integrate cost-effective distributed resources into distribution planning consistent with the goal of yielding net benefits to ratepayers.

5. Identify barriers to the deployment of distributed resources, including, but not limited to, safety standards related to technology or operation of the distribution circuit in a manner that ensures reliable service.

(c) The commission shall review each distribution resources plan proposal submitted by an electrical corporation and approve, or modify and approve, a distribution resources plan for the corporation. The commission may modify any plan as appropriate to minimize overall system costs and maximize ratepayer benefit from investments in distributed resources.

(d) Any electrical corporation spending on distribution infrastructure necessary to accomplish the distribution resources plan shall be proposed and considered as part of the next general rate case for the corporation. The commission may approve proposed spending if it concludes that ratepayers would realize net benefits and the associated costs are just and reasonable. The commission may also adopt criteria, benchmarks, and accountability mechanisms to evaluate the success of any investment authorized pursuant to a distribution resources plan.

https://leginfo.legislature.ca.gov/faces/billNavClient.xhtml?bill_id=201320140AB327
Section 769 defines Distributed Energy Resources (DER) as distributed renewable generation resources, energy efficiency, energy storage, electric vehicles, and demand response technologies located on the distribution system.
Optimal locations for DERs

Section 769 requires the utility’s distribution resources plan proposal to identify optimal locations for the deployment of distributed resources.

Optimal locations are locations in the distribution system where DERs:

• Provide benefits to the grid (e.g., avoid investments in distribution infrastructure, safety or reliability benefits); and/or
• Have lowest cost impacts to the grid

Optimal locations also enable PG&E to make better distribution investment decisions for its customers

• Procure DERs that provide net ratepayer benefit
• Proactively invest to accommodate DERs
Locational Net Benefit Analysis (LNBA)

Section 769 requires the distribution resources plan proposals to evaluate locational benefits and costs of distributed resources.

**LNBA estimates DER location-specific benefits or costs**

- **Major benefit (or cost) categories:**
  - Distribution
  - Transmission
  - Generation
  - Societal/Safety

- Each category has one or more benefit/cost component
- Each component can be positive or negative

**Net Benefits = NPV (Benefits) – NPV(Costs)**
# LNBA benefit/cost components

<table>
<thead>
<tr>
<th>Categories</th>
<th>LNBA Components</th>
</tr>
</thead>
<tbody>
<tr>
<td>Distribution</td>
<td>Distribution Thermal Capacity Capital Investment</td>
</tr>
<tr>
<td></td>
<td>Voltage and Power Quality Capital and Operating Expenditures</td>
</tr>
<tr>
<td></td>
<td>Distribution Reliability and Resiliency Capital and Operating Expenditures</td>
</tr>
<tr>
<td>Transmission</td>
<td>Transmission Capital and Operating Expenditures</td>
</tr>
<tr>
<td>Generation</td>
<td>Generation Energy and GHG</td>
</tr>
<tr>
<td></td>
<td>Energy Losses</td>
</tr>
<tr>
<td></td>
<td>Generation Capacity:</td>
</tr>
<tr>
<td></td>
<td>System, local, and flexible capacity for Resource Adequacy</td>
</tr>
<tr>
<td></td>
<td>Ancillary Services:</td>
</tr>
<tr>
<td></td>
<td>Spinning, non-spinning, regulating reserves, flexi-ramp</td>
</tr>
<tr>
<td></td>
<td>RPS Procurement cost</td>
</tr>
<tr>
<td>Societal/public safety</td>
<td>Qualitatively</td>
</tr>
</tbody>
</table>
Integrating DERs in planning processes

Load Forecasting

Load Forecast incorporates existing DERs + organic DER growth

Integrated Resource Planning (IRP)

IRP identifies cost-effective DERs considering local and system impacts

Transmission Planning

Transmission Planning identifies locations where DERs can defer transmission upgrades

Distribution Planning

Distribution Plan identifies optimal locations where DERs can defer distribution investment or hosting capacity is available
Thank you!

Antonio Alvarez
Renewable Integration Manager
Pacific Gas & Electric (PG&E)
California
What’s a Watt Worth
Dennis Elsenbeck
National Grid
Formation of a Demonstration

- Reforming the Energy Vision (REV)
  - Technical Innovation
  - Ageing Infrastructure

- Distributed System Platform (DSP)
  - System Planning, Grid Operations & Market Operations
  - Deploys Distributed Energy Resources Based on Market and System Conditions

- Stakeholder Engagement
  - Market Driven View of Evolving Industry
  - Buffalo Niagara Medical Campus
120 Acres in Buffalo – 2 million SQFT Growth – 5,000 New Employees

- Installed Solar
- Off Grid Wind & Solar Lighting
- Bike & Car Share Program
- Grid Modernization Study
- eTHINK smartHome
- 25 Electric Vehicle Charging Stations
- Micro Grid Study
- LED Parking Lot Lighting
- LMI Neighborhood Solar
Distributed System Implementation

- Investment Balance
  - Supply
  - Demand
  - Distribution

- Evolving Pricing Model
  - Valuation
  - LMP + D + E
    - Location Marginal Price
    - Value of “D” (Offset)
    - Value of “E” (Credit?)
The Role of the DSP

- Consider diverse and distributed energy resources
- Coordinate with ISO and bulk systems
- Integrate market and operations drivers in forecasts
- Operate in a secure, reliable and resilient manner
- Increase system flexibility in a dynamic environment
- Implement economic and energy efficient solutions
- Provide rich information for consumers and suppliers in a transparent fashion
- Utilize new technologies and develop innovative products and services
Basic Demonstration Elements

National Grid DSP

Kaleida Health
- POC 1
  - DER 1
  - DER 2
  - DER 3
  - ... DER n

Roswell Park
- POC 2
  - DER 1
  - DER 2
  - DER 3
  - ... DER n

Univer. of Buffalo
- POC 3
  - DER 1
  - DER 2
  - DER 3
  - ... DER n

BNMC Operator 4
- POC 4
  - DER 1
  - DER 2
  - DER 3
  - ... DER n

... BNMC Operator N
- POC N
  - DER 1
  - DER 2
  - DER 3
  - ... DER n
<table>
<thead>
<tr>
<th>DSP Service</th>
<th>Annual</th>
<th>Day-Ahead</th>
<th>DER Response Examples</th>
</tr>
</thead>
<tbody>
<tr>
<td>Energy Supply</td>
<td>X</td>
<td>X</td>
<td>Generation, energy storage, demand response</td>
</tr>
<tr>
<td>Volt-Ampere Reactive (VAR) Support</td>
<td>X</td>
<td>X</td>
<td>Power electronics (energy storage, solar PV inverter) power factor setting</td>
</tr>
<tr>
<td>Voltage Management</td>
<td></td>
<td>X</td>
<td>Power electronics (energy storage) voltage control, VAR control (indirect)</td>
</tr>
<tr>
<td>Peak Load Modification</td>
<td>X</td>
<td>X</td>
<td>Generation, energy storage, demand response</td>
</tr>
<tr>
<td>Dynamic Load Management</td>
<td></td>
<td>X</td>
<td>Demand response</td>
</tr>
</tbody>
</table>
### Phases of the Demonstration

<table>
<thead>
<tr>
<th>Phase 1: Financial Model</th>
<th>Phase 2: Technology Development</th>
<th>Phase 3: Field Demo</th>
</tr>
</thead>
<tbody>
<tr>
<td>3 months</td>
<td>9 months</td>
<td>15 months</td>
</tr>
</tbody>
</table>

- **Phase 1: Financial Model**
  - Design and develop financial model and pricing scenarios
  - Test and solicit feedback from DER and POC operators

- **Phase 2: Technology Development**
  - Develop new scenarios and pricing models if necessary
  - Is it attractive to DER and POC operators
  - Design and develop DSP and POC hardware and software
  - Test and solicit feedback from DER and POC operators

- **Phase 3: Field Demo**
  - Evaluate and solicit feedback from DER and POC operators
  - M&V DSP, POC, and DER performance
  - Is it attractive to DER and POC operators
  - Deploy DSP and POC hardware and software
Phased Demonstration Testing

- **Phase 1 – Financial Model**
  - Financial Model has Sufficient Value for Distributed Energy Resource Participation (LMP + D)

- **Phase 2 – Technical Development**
  - DSP can create a Technical and Financial Platform for DERs
  - Point of Control can be Communication’s Portal

- **Phase 3 – Field Demonstration**
  - The DSP and POC Model can enable Distribution System Benefits by “Un-locking” DER Assets
    - Unconstrained and Grid-constrained Operations
Thank you

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Director of Stakeholder Engagement and Policy
National Grid, New York
What’s a Watt Worth

Sai Moorty

ERCOT
Proposal for Integrating DER into ERCOT (ISO) Wholesale Markets

Sainath (Sai) Moorty, ERCOT

NREL
August 17, 2016
Agenda

- ERCOT’s changing resource mix
- Distributed Energy Resources … an ERCOT perspective
- Overview of ERCOT’s proposal to integrate DER
- Impacts of significantly large scale penetration of DER on ERCOT systems
- ERCOT’s proposal to integrate DERs into wholesale markets
ERCOT’s Changing Resource Mix
Changing Resource Mix (% Capacity)

### Late 1990s
- Gas-Steam: 50%
- Coal: 25%
- Nuclear: 8%
- Gas-CT/CC: 5%
- Cogen: 11%
- Other: 0.9%
- Renewables: 0.008%

### 2015
- Gas-Steam: 36.5%
- Coal: 22.4%
- Nuclear: 5.7%
- Cogen: 5.3%
- Renewables: 13.8%
- Other: 1.4%

**The Future**
Potential impacts of new and pending environmental regulations, lower PV costs, extension of tax subsidies

**More renewables, especially distributed**
Texas is #1 in the U.S. in wind capacity.
If the ERCOT Region were a separate country, we’d be #6 in the world in wind generation capacity (as of end of 2015).
Weather Impacts on Load by Customer Type

Thursday, March 12, 2015
5:00 PM
ERCOT Load: 32,955 MW
Temperature in Dallas: 69°

Mon., Aug. 10, 2015
5:00 PM
ERCOT Load: 69,659 MW
Temperature in Dallas: 107°

~37,000 MW of weather-sensitive load -- 53% of peak

- Customer class breakdown is for competitive choice areas; percentages are extrapolated for munis and co-ops to achieve region-wide estimate
- Large C&I are IDR Meter Required (>700kW)
- 15-minute settlement interval demand values

Customer class breakdown:

- Residential: 50.4%
- Small Commercial: 24.9%
- Large C&I: 24.7%

3/12/2015 IE 17:00
8/10/2015 IE 17:00

Residential: 26.2%
Small Commercial: 29.0%
Large C&I: 44.8%
Distributed Energy Resources (DERs) …an ERCOT perspective
**Distributed Energy Resources**

- **DERs potentially include:**
  - Rooftop solar - intermittent
  - Fossil fuel generators
  - Storage devices
  - Fuel cells
  - Combinations of the above at single or multiple points of interconnection at <60kV

- **DERs may be co-located with load behind the meter**

- Many DER management systems include distribution level demand response (DR) as part of the DER performance

- However, integrating Demand Response (DR) into a DER involves some issues specific to ERCOT

- The PUC Rule that established ERCOT’s Nodal Market Design requires:
  - Generation to be settled at a (Nodal) Locational Marginal Price
  - Load to be settled at the weighted average price of all LMPs in a Load Zone
    - Exception: Load (energy) used to charge a storage device
    - There are 4 competitive Load Zones in ERCOT: North, South, West and Houston

- This implies that DR cannot be part of a DER that may seek to be **settled at a Nodal price**, absent a Rule change.
How much DER capacity is out there?

- DG reporting is a work in progress.
  - All DG >1 MW must register with ERCOT
    - Assuming it injects to the grid and…
    - Is not registered with PUC as Self-Generation
  - Investor-owned TDSPs submit:
    - Annual DG Interconnection reports to PUC
    - Regular updates to ERCOT Profile Codes
  - Munis and Co-ops (NOIEs) report:
    - Data on units >50 kW that inject energy to the grid
    - Some anecdotal summaries to City Councils, etc.

- With all that in mind, here’s what we have:
DG snapshot as of Dec. 31, 2015

From Competitive Choice TDSP annual reports to PUC, plus estimated NOIE DG
DG Capacity based on these reports: 1,101 MW
Capacity from Generation Resources based on Dec. 2015 CDR: 79,280 MW

<table>
<thead>
<tr>
<th>Units</th>
<th>&lt;1MW #</th>
<th>1-10MW #</th>
<th>≥10 MW*</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>138</td>
<td>[VALUE]</td>
<td>224</td>
</tr>
<tr>
<td></td>
<td>~13,800 Units</td>
<td>86 Units</td>
<td>16 Units</td>
</tr>
<tr>
<td>total</td>
<td>877</td>
<td>224</td>
<td></td>
</tr>
</tbody>
</table>

Installed MW
- **Fossil**: 877
- **Renewable**: 224

* An unknown number of these units may be among the 77 units registered with PUC as Self-Generators.
# Anecdotal as reported by Austin Energy & CPS Energy, plus some other NOIE >50kW. NOIEs are not required to report unregistered DG to ERCOT unless >50kW and injects to grid.
Why DER is Growing?

1. Consumer desire for independence
   a) Mandated or strongly encouraged for critical infrastructure
   b) Economically desirable to guarantee limited interruption of service

2. Environmental consciousness
   a) Non-economic reasons

3. Declining costs of DER acquisition and operation
   a) Tax credits
   b) Reduction in costs
Overview of ERCOT’s Proposal To Integrate DER
Typical Distribution Grid Topology

Distribution Grid

- Predominantly Radial Topology
- Urban Areas more meshed
- Limited telemetry available at distribution voltage relative to available telemetry transmission level
- More resilient to unbalanced 3 phase flow
- Mainly designed for unidirectional power flow from transmission to consumer
- DER can be single phase - residential
Integrating DERs into ERCOT ISO Operations – Starting Points

1. ERCOT is responsible for reliable operation of the transmission grid (≥60 KV). The interface to the distribution grid is modeled as a Load (i.e. substation transformer interconnecting transmission to distribution is represented as a Load).

2. Increased DER penetration will have reliability impacts on the distribution grid (< 60 KV) well before measurable reliability impacts occur on the transmission grid reliability operations that ERCOT is responsible for.

3. DER installation requires interconnection agreement with the local Distribution Service Provider (DSP).

4. Typically DSPs have a limit on the total aggregate DER capacity allowed on a feeder or the secondary of a substation transformer before distribution grid upgrades are required, the cost of which are borne by the DER owner.

From ERCOT’s perspective as the transmission grid operator:

Very significant DER penetration at individual substation transformers will need to happen before DER operations -- intermittent or self-dispatched -- at that location will overshadow the natural hourly variability of the actual demand at that location.
ERCOT’s Proposal to Integrate DER

1. Key areas pertaining to DERs that ERCOT has identified as gaps:
   1. Lack of DER visibility (location, type, capacity)
   2. What are they doing? (forecast of intermittent DER – solar forecast)

2. Monitor growth of DER by collecting data:
   1. Location information relative to the transmission grid (e.g. closest station, bus)
   2. DER type and capacity (Fuel: Solar, Natural Gas, Diesel, etc., Storage, MW and MWh capacity)
   3. Others (if available)

3. Review ERCOT software systems and processes to prepare a plan to address scenario where there is significant DER penetration, e.g. (short list below)
   1. Load Forecast
   2. State Estimator
   3. Contingency Analysis

4. Develop a market framework that enables DERs to participate in wholesale markets for energy and Ancillary Services.

ERCOT published a concept paper on 8/20/15 describing a proposal for DERs to participate in wholesale markets (energy and Ancillary Service) where their energy injection is settled at the closest transmission bus LMP:

http://www.ercot.com/content/wcm/key_documents_lists/72784/DER_Whitepaper_082015.docx
5. ERCOT operations model used in Energy Management System (EMS) and Market Management System (MMS) will not be expanded to include modeling the distribution grid (<60KV) down to DER location.

6. Map DERs to the closest transmission modeled load (representing substation transformer). i.e. not explicitly modeled in power flow or state estimation. Mapping provides alternate mechanism for handling DER, e.g. LMP at Load Bus, Bus Load Forecast.
Impacts Of Significantly Large-Scale Penetration of DER on ERCOT Systems
Load Forecast

Difficulties in creating an accurate load forecast - short term and mid term

Cause:
  a) Lack of DER visibility (location, type, capacity)
  b) Lack of ISO control over dispatch (not participating in wholesale markets)
  c) Variability of PV generation (lack of solar forecasting)

Effect:
  a) Potential need to procure additional Ancillary Services
  b) Potential for inaccuracies in Reliability Unit Commitment (RUC)
  c) Potential for an increase in price volatility

Mitigation Plan:
Enhance Load Forecast tools/processes to consider solar insolation at various locations coupled with locational awareness of DER installations (type, capacity)
State Estimator (SE)

Difficulties with State Estimator accuracy, load distribution factor (LDF) adaptation

Cause:
   a) State estimation of Loads typically are not allowed to be negative. State Estimator output processing will floor the load MW value to zero. This may be inaccurate with significant penetration of DER at certain locations, where, there could be back-feed into the transmission grid

Effect:
   a) Inaccurate LDFs (zero instead of negative)
   b) Real-Time Contingency Analysis may start with inaccurate Base Case (some loads are zero instead of negative)
   c) Other applications that use these inaccurate LDFs can be impacted
      a) Outage evaluation at different load load levels use LDFs to scale up/down individual loads
      b) Day-Ahead Market (DAM), Reliability Unit Commitment (RUC) applications, similarly use LDF to scale up/down individual loads based on hourly load bids or hourly load forecast

Mitigation Plan:
1. Modify State Estimator and LDF adaptation system to use DER locational data that allows for loads MW values to be negative
2. Modify how Outage Evaluation, DAM and RUC utilizes LDFs
Contingency Analysis (CA)

Inaccuracies in the results of Contingency Analysis

Cause:

a) Lack of DER visibility (location, voltage response characteristics, type, capacity)

Effect:

a) False positive: Incorrectly mark an analyzed contingency as being secure where, a voltage drop on a transmission bus can cause tripping of DER, which causes an increase in load. This is not captured in the contingency definition.

b) False negative: If DERs provide reactive support, then a low voltage due to a contingency may be incorrectly analyzed as being insecure

Mitigation Plan:

1. Enhance Contingency Analysis tool to consider locational DER information
2. Develop models to simulate voltage response characteristics of DER at relevant transmission bus
ERCOT’s Proposal To Integrate DERs Into Wholesale Markets
Market Participants

Who are the Players?

QSE
Qualified Scheduling Entities

LSE
Load Serving Entities

TSP
Transmission Service Providers (Wires)

DSP
Distribution Service Providers (Wires)

Resource Entity
Resource Entities
New Opportunities for PV and Storage: Smart Inverters

Smart Inverter functions (future IEEE standards, CPUC Rule 21,...)

a. Two-way communication/control between DER and remote entity
b. Anti-Islanding Protection
c. Low and High Voltage Ride-Through
d. Low and High Frequency Ride-Through
e. Dynamic Volt-Var Operation
f. Ramp Rates
g. Fixed Power Factor
h. Soft Start Reconnection
## Metering Types

<table>
<thead>
<tr>
<th>Type</th>
<th>Notes</th>
<th>Notes</th>
</tr>
</thead>
<tbody>
<tr>
<td>Unidirectional</td>
<td>Measures consumption only</td>
<td>Load only (no DG)</td>
</tr>
<tr>
<td>‘Traditional’ Net metering</td>
<td>Single-channel non-directional. Single data point representing net Load minus net on-site generation over a billing period (could be a negative number).</td>
<td>Mostly disallowed by PUC Rule 25.213.</td>
</tr>
<tr>
<td>Bi-directional</td>
<td>Two data points for each 15-minute interval: measures net in-flow to the point of delivery (i.e., may be reduced by on-site DG), and net exports to the grid from the point of delivery.</td>
<td>Required by PUC Rule for investor-owned TDSPs</td>
</tr>
<tr>
<td>Dual metering</td>
<td>Two meters, two data points for each 15-minute interval: measures gross Load and gross generation.</td>
<td>Allows DSP to bill customer based on gross consumption; allows LSE to pay customer for gross generation.</td>
</tr>
</tbody>
</table>
From the diagram below, for a given 15-minute Settlement Interval X, the two meters will each provide net outflow and inflow readings.

Meter 1 reads:
- A for net outflows and,
- B for net inflows

Meter 2 reads:
- C for net outflows and,
- D for net inflows

For a given 15-minute Settlement Interval X:
- Energy consumption by Native Load + Aux Load = B+C-(A+D)
- Energy generated by DER = C
- Energy consumed for charging storage = D
ERCOT Proposal For Integrating DER Into Wholesale Markets

Current DER wholesale energy market pricing:

• DERs today are settled on the applicable LZ SPP if the energy meter records a net injection into the grid (at meter location)

• Applies to both:
  – Injections to the grid by registered DG with QSE representation
  – Negative load treatment for an unregistered DG’s Load Serving Entity

• In other words, DERs today are ‘passive’ participants to prices:
  – Controlled passive response – e.g., fossil fuel, PV + storage, or storage – may chase LZ SPPs
  – Uncontrolled passive response – e.g., pure PV – they produce when the sun is shining
ERCOT Proposal For Integrating DER Into Wholesale Markets

ERCOT Proposal for Locational pricing for DER

• If DERs were eligible to be settled on more granular pricing, then passive response could better align with grid conditions
  – Higher local prices indicate local scarcity – signaling DERs to chase these prices if they are capable of doing so

• DERs would need to be mapped to appropriate electrical bus(es), and settled at that electrical bus (or average of multiple buses) price

• Proposed to be optional: Entity representing the DER could choose whether to get LZ SPP pricing or the locational price

• If it’s the locational price, then the DER should meet further requirements:
  – Telemetry or some other type of real-time or near-real-time communication to the ISO (active power, status, etc.)
  – Revenue quality metering (AMI/IDR/EPS) that measures DER gross output separate from the gross load behind common service delivery point
  – This is necessary to ensure compliance with PUC Rules 25.501, which requires all load in the ERCOT region to be settled at the applicable Load Zone Price
ERCOT Proposal For Integrating DER Into Wholesale Markets

3 potential categories:

- **DER Minimal**: Business as usual, what we have today, passive participation, price takers, settled at Load Zone LMPs

- **DER Light**: Passive participation (no ERCOT dispatch) but settled at the Nodal (local) wholesale price, rather than at the average price at the Load Zone
  - Would require separate metering of gross load and gross generation

- **DER Heavy**: Active participation in Energy and AS, much like Generation Resources today
  - Would require:
    - Separate metering of gross load and gross generation
    - Significant real-time data to ERCOT
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<thead>
<tr>
<th>DER Types</th>
<th>Features</th>
<th>DER Minimal</th>
<th>DER Light</th>
<th>DER Heavy</th>
</tr>
</thead>
<tbody>
<tr>
<td>Energy Settled at:</td>
<td>Load Zone SPP</td>
<td>Price at Local electrical bus(es)</td>
<td>Logical Resource Node (price at Local electrical bus(es))</td>
<td></td>
</tr>
<tr>
<td>Energy Market Participation</td>
<td>Self-responding</td>
<td>Self-responding</td>
<td>SCED-dispatched</td>
<td></td>
</tr>
<tr>
<td>Ancillary Service Market Participation</td>
<td>Not eligible</td>
<td>Not eligible</td>
<td>Eligible</td>
<td></td>
</tr>
<tr>
<td>Aggregation Allowed?</td>
<td>N/A</td>
<td>Yes</td>
<td>Yes</td>
<td></td>
</tr>
<tr>
<td>Metering Required</td>
<td>Single meter OK (15-minute revenue quality) at POI</td>
<td>Separate (dual) metering for Generation and native Load</td>
<td>Separate (dual) metering for Generation and native Load</td>
<td></td>
</tr>
<tr>
<td>Telemetry or telemetry-light to and from ERCOT</td>
<td>Not required</td>
<td>Real-time or near real-time with multiple attributes</td>
<td>Real-time or near real-time with multiple attributes</td>
<td></td>
</tr>
<tr>
<td>COP, Outage Schedule, Offers/Bids, etc.</td>
<td>N/A</td>
<td>Possible “light” version required</td>
<td>Required</td>
<td></td>
</tr>
<tr>
<td>CRR/PTP Implications</td>
<td>None</td>
<td>None</td>
<td>Maybe</td>
<td></td>
</tr>
</tbody>
</table>
DER Minimal
ERCOT has developed a concept paper to help integrate DERs into the wholesale market.

Main concept is to allow DERs to be settled at local (Nodal) prices instead of zonally averaged prices.

Would provide proper incentives for DER locating and could contribute to local congestion management.

Hypothetical DER configuration: Generator and storage device combination metered separately from native and auxiliary load; DER mapped to one or more Load Points in the transmission network model.
Aggregated DER Modeling and Challenges

• Modeling – ERCOT proposal based on combined cycle model
  – ERCOT current proposal allows for multiple generation technologies (Solar, Solar+Storage, etc.) to make up a given DER aggregation

• Managing aggregation membership (move-in, move-out)

• Measurement & Validation
  – Required for ensuring telemetry of aggregation (virtual in many cases) is sufficiently accurate
  – Big Data Analytics & statistical sampling
Current Status

Stakeholders are discussing the feasibility of an intermediate step where a registered Distribution Generator (typically between 1 MW and 10 MW) could actively participate in wholesale energy markets with an energy offer but get settled on a Load Zone price.

• Does not require separate meter (i.e., can be co-located with Load)

• Like DER Heavy, requires real-time telemetry
Thank you

Sai Moorty
Principle, Market Design and Development
Electric Reliability Council of Texas (ERCOT)
Questions?

Participants are joined in listen-only mode.

Use the Q&A panel to ask questions during the webinar.

To ask a question: Type your question in the Q&A gotowebinar toolbar.

We will have a few minutes of Q&A between each presentation and group discussion at the very end.

The webinar is being recorded and will be posted on the DGIC site: http://www.nrel.gov/tech_deployment/dgic.html
Questions?

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• Participate in the Collaborative and shape the discussion by signing up through the DGIC web page: http://www.nrel.gov/tech_deployment/dgic.html
• Webinar slides and recording available here also!
Thank You!

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