Locational Net Benefits Analysis Working Group

November 13, 2017

In-person meeting

drpwg.org

MORE THAN SMART

Agenda

1:30 – 1:45: Agenda and overview of schedule
1:45 – 2:30: Avoided line losses (IOU presentation on preliminary study results of line loss variation) (Group I)
2:30 – 3:30: Avoided energy (Review results of IOU evaluation of existing public DLAP forecasts and forecast price methodology) (Group I)
3:30 -3:45: Break
3:45 – 4:30: Unplanned projects (Group III)

ICA and LNBA Working Group Background

ICA and LNBA WG Purpose - Pursuant to the May 2, 2016, Assigned Commissioner's Ruling (ACR) in DRP proceeding (R.14-08-013), the Joint Utilities are required to convene the ICA and LNBA WG to:

1. Refine ICA and LNBA Methodologies and Requirements
2. Authorize Demonstration Project A and Project B

CPUC Energy Division role

- Oversight to ensure balance and achievement of State objective (ensure adequate stakeholder representation in consensus statements, keeping WG activities on track with Commission expectations/needs, demonstration project results review, quality control on deliverables)
- Coordination with both related CPUC activities and activities in other agencies (IDER CSF WG, CEC and CAISO interagency matters, interconnection/Rule 21/SIWG, other proceedings that may impact or be impacted by locational value calculation such as AB 350/IRP and LTPP/TPP/RPS)
- Steward WG agreements into CPUC decisions when necessary

More Than Smart role

- Engaged by Joint Utilities to facilitate both the ICA & LBNA working groups. This leverages the previous work of MTS facilitating stakeholder discussions on ICA and LBNA topics.

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Schedule

- November:
  - 11/13 (ICA and LNBA): in-person meeting
  - 11/14 (LNBA): Final deadline for response to original proposals
- December:
  - 12/6 (LNBA): Final comment on November meeting discussions
  - 12/12 (LNBA): MTS circulates second draft
  - 12/16 (LNBA): First round of edits
  - Mid-December (*tentative) – in-person WG meeting*
  - 12/28 (LNBA): MTS circulates second draft
  - 1/5 (LNBA): Final edits
  - 1/8 (ICA and LNBA): Report Due

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Locational Net Benefits Analysis (LNBA) Working Group

November 13, 2017

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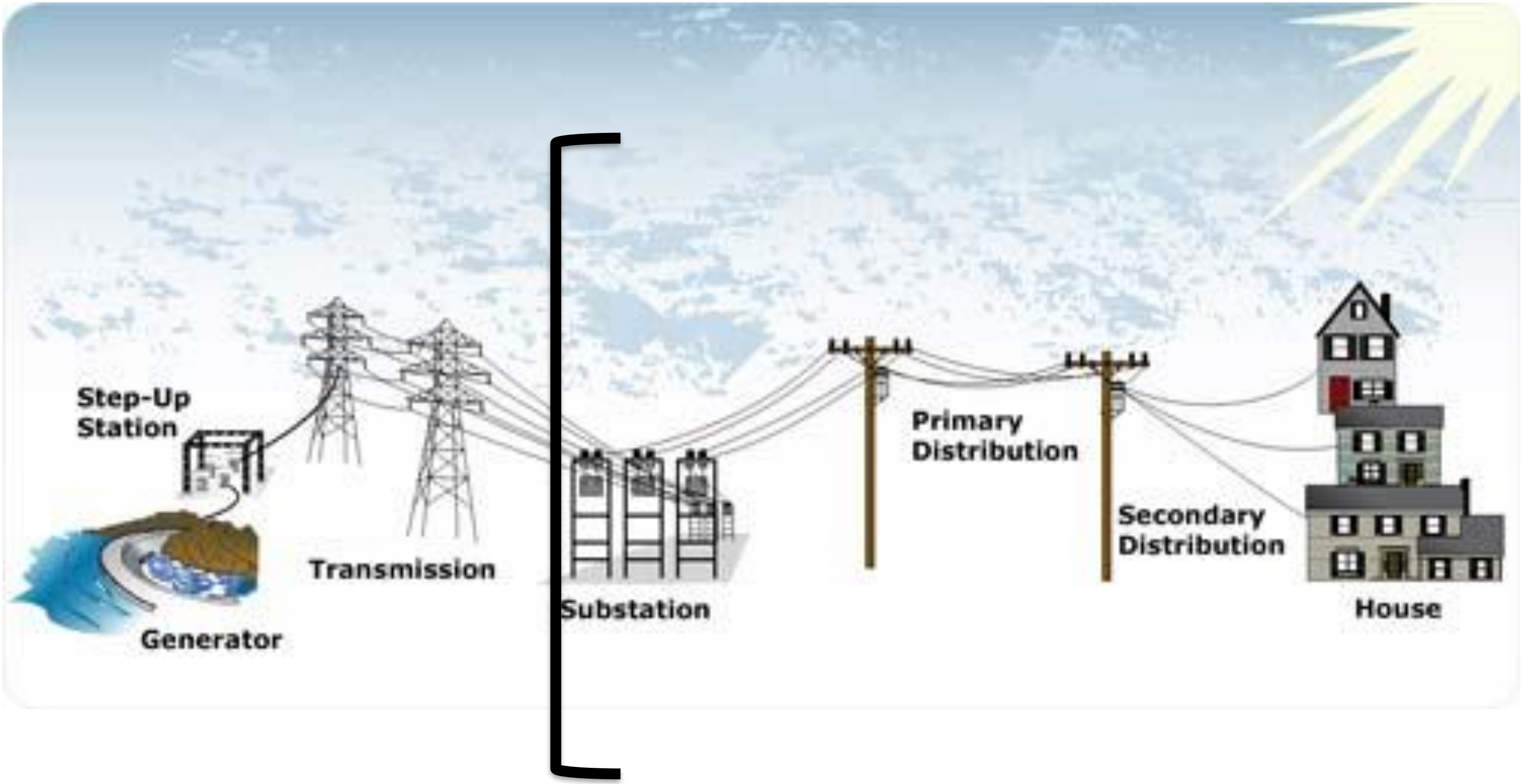
Reminder: Today's discussion is on Distribution System Losses



Reminder: Losses in LNBA

Two parts of the LNBA currently use loss factors to calculate avoided cost:

1. **Peak loss factors for Generation Capacity Avoided Cost**
   – System-level peak loss factors (marginal T&D kW loss factor at peak hour) are used to calculate a DER's generation capacity procurement avoided cost (e.g. **X** MW customer load reduction @ peak = **X***1.10 MW generation capacity reduction).

2. **Energy loss factors for Generation Energy Avoided Cost**
   – Energy loss factors (combined T&D kWh loss factor for annual energy) are used to calculate a DER's energy procurement avoided cost. (e.g. **Z** MWh/yr customer load reduction = **Z***1.10 MWh/yr generation reduction)

A third Loss factor is used to DER minimum size to defer a T&D upgrade:

1. **Project-specific loss factor for DER deferral sizing**
   – DERs can reduce an overload upstream that would otherwise require T&D investment. The relationship between the magnitude of the overload and the size of the DER load reduction depends in part on losses between the DER solution and the overloaded equipment. (e.g. **X** MW customer load reduction on secondary = **X***1.10 MW load reduction in substation transformer overload during local peak).

In the Demo B LNBA tool these calculations all use system average loss factors rather than location-specific factors

Reminder: Current Loss Factors in DERAC

Table 12. Marginal energy loss factors by time-of-use period and utility.

Time Period	PG&E	SCE	SDG&E
Summer Peak	1.109	1.084	1.081
Summer Shoulder	1.073	1.080	1.077
Summer Off-Peak	1.057	1.073	1.068
Winter Peak	-	-	1.083
Winter Shoulder	1.090	1.077	1.076
Winter Off-Peak	1.061	1.070	1.068

Table 11: Generation capacity loss factors

	PG&E	SCE	SDG&E
Generation to meter	1.109	1.084	1.081

Table 5. Losses factors for SCE and SDG&E transmission and distribution capacity.

	SCE	SDG&E
Distribution	1.022	1.043
Transmission	1.054	1.071

Table 6: Losses factors for PG&E transmission and distribution capacity.

	Transmission	Distribution
CENTRAL COAST	1.053	1.019
DE ANZA	1.050	1.019
DIABLO	1.045	1.020
EAST BAY	1.042	1.020
FRESNO	1.076	1.020
KERN	1.065	1.023
LOS PADRES	1.060	1.019
MISSION	1.047	1.019
NORTH BAY	1.053	1.019
NORTH COAST	1.060	1.019
NORTH VALLEY	1.073	1.021
PENINSULA	1.050	1.019
SACRAMENTO	1.052	1.019

Reminder: Study Plan

1. Select a sample size of distribution feeders to evaluate in preliminary study
2. Define circuit types to reflect differing characteristics
   – i.e. Rural large service area, urban small service territory , and suburban medium size territory
   – Uniform loading, spot load, express run circuit
   – High % loaded circuit, medium %. Low %
3. Evaluate base circuit model for maximum, minimum, and median loading levels to see the baseline %/kW losses on each circuit
4. Model generation on baseline conditions created in #2
5. Record the kW losses from baseline condition determined from #2
6. Calculate maximum losses % change and min loss %
7. Use line loss study results to estimate sensitivity on LNBA results
8. Share results and with CPUC and greater WG on/around November 1 to determine next steps

SCE – Line Loss Study

Methodology

- Base losses were calculated on 15 representative circuits
- A 1MW generator was modeled at each 10% impedance of the circuit from the substation
  - Study was completed with a single 1MW generator at a time
- Percent reduction of losses relative to a 1 MW generator
  - (Base losses - Line losses)/1000 kW at each 10% impedance

SCE – Line Loss Study

Technical Observations (4 kV)

- No reduction in average line losses were determined at any given location when simulating a 1 MW generator on the selected circuits
  - Adding 1 MW generator resulted in reverse power flow, thus increasing line losses
  - Loading conditions and circuit configuration did not affect the outcome of losses

- Secondary Line Loss reductions only occur when generators can offset their own site load
  - Exporting power to the primary side of the transformers increases line losses
  - Exporting power to a secondary customer increases line losses due to impedance of conductors, cables, and transformers

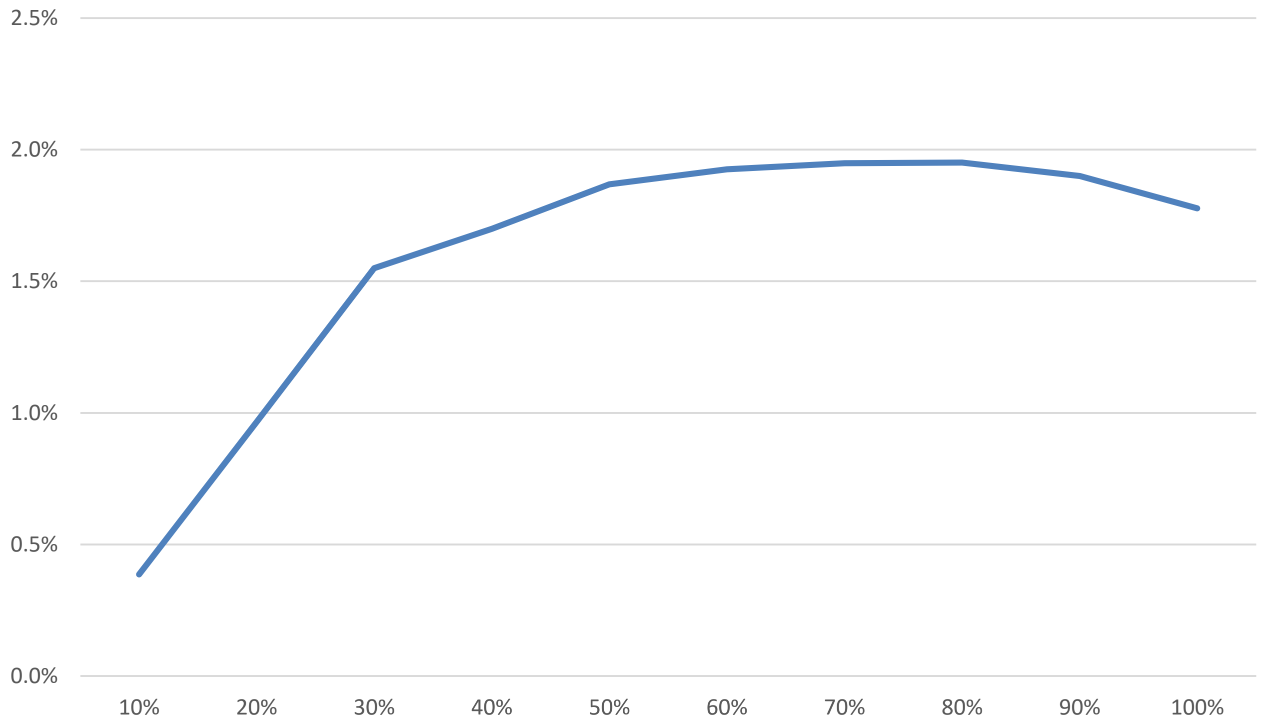
SCE – Line Loss Study

Technical Observations (12 & 16 kV)

- There is a similar reduction of line losses on the selected circuits when simulating a 1 MW generator
  - Maximum and average loading conditions on the selected feeders contributed to the reduction of losses
  - Concentrated loading sections on the selected feeders contributed to the reduction of losses
  - Express circuits where spot loading is at the end of the line contributed to the reduction of losses
  - There is a line loss reduction of 2% per MW installed

SCE – Line Loss Study

System Average based on 1 MW Nameplate



Inverter Nameplate Rating (up to min load)	Percent Reduction
250 kW	0.5%
500 kW	1%
750 kW	1.5%
1000 kW	2%
2000 kW	4%

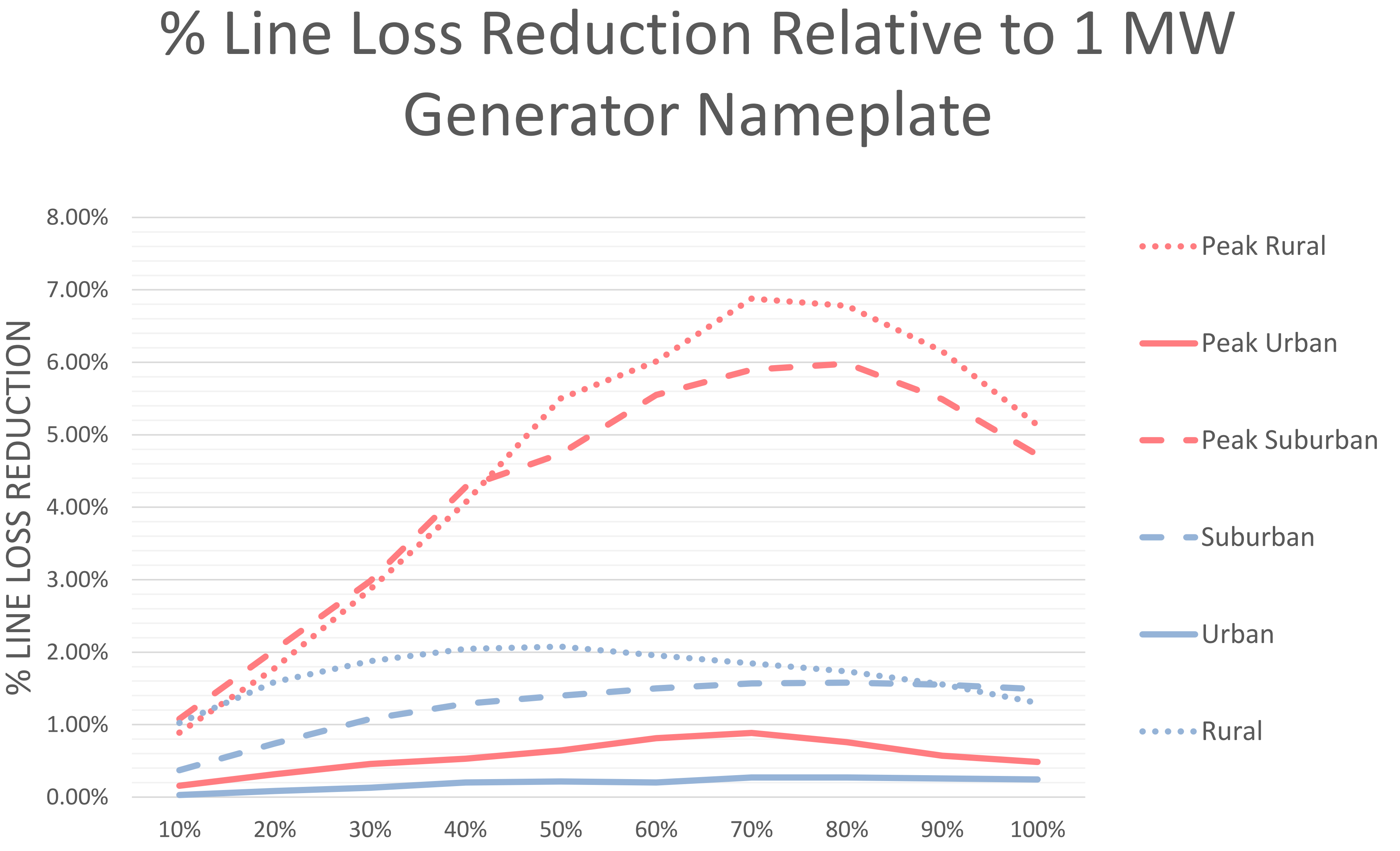
System Average by every 10% impedance of the selected feeders

SCE – Line Loss Study

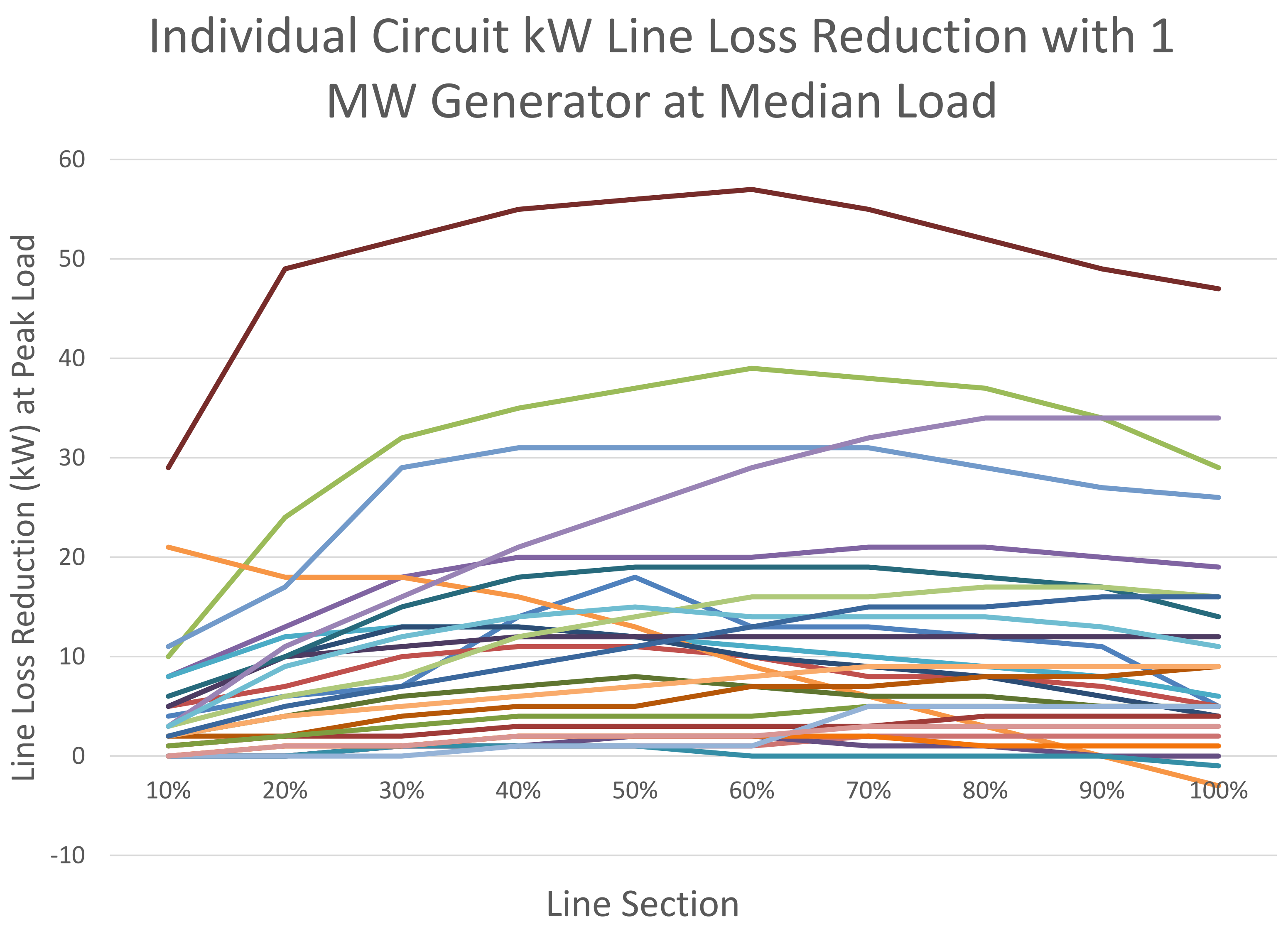
Result & Recommendations

- Line Loss reduction benefits may not be applicable to distribution-connected energy storage due to internal losses
  - Unless Energy Storage charges from a renewable source and not from the grid
- For 4kV feeders, no benefit of line losses reductions shall be given to generators
- As long as the generator nameplate rating is less than the circuit minimum load, there will be a reduction in line losses
  - For 12 & 16 kV feeders, the reduction of losses is 2% per MW installed up until the minimum loading of the circuit
- Increasing the generator size will also increase the likelihood of reverse power flow, which will increase the line losses on the circuit
  - Under maximum loading conditions, a circuit may experience a reduction of losses with a 1 MW generator. However, the losses will increase when connecting a 5 MW generator under the same loading conditions.

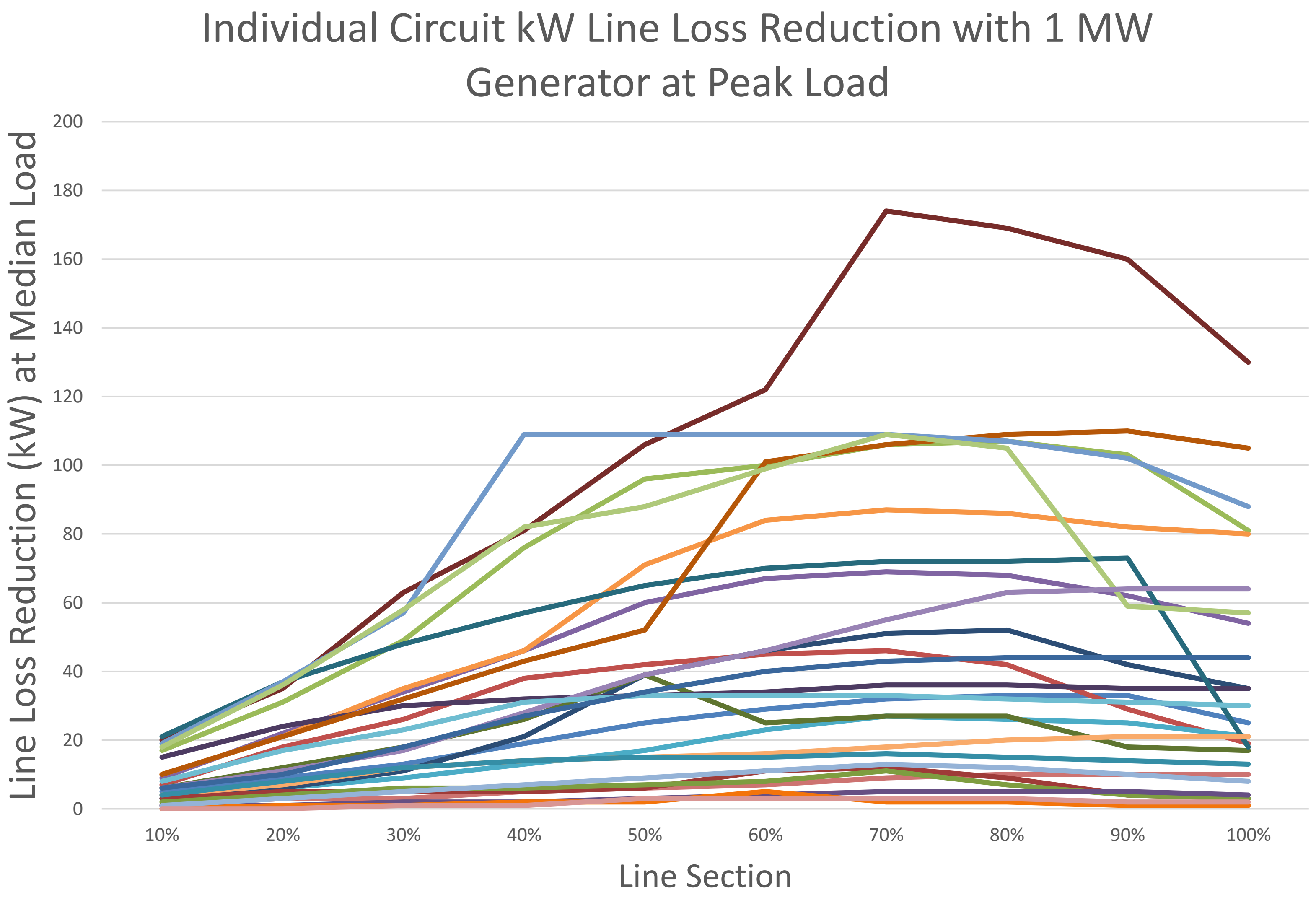
SDG&E – Line Loss Study



SDG&E – Line Loss Study



SDG&E – Line Loss Study



Secondary Line Losses

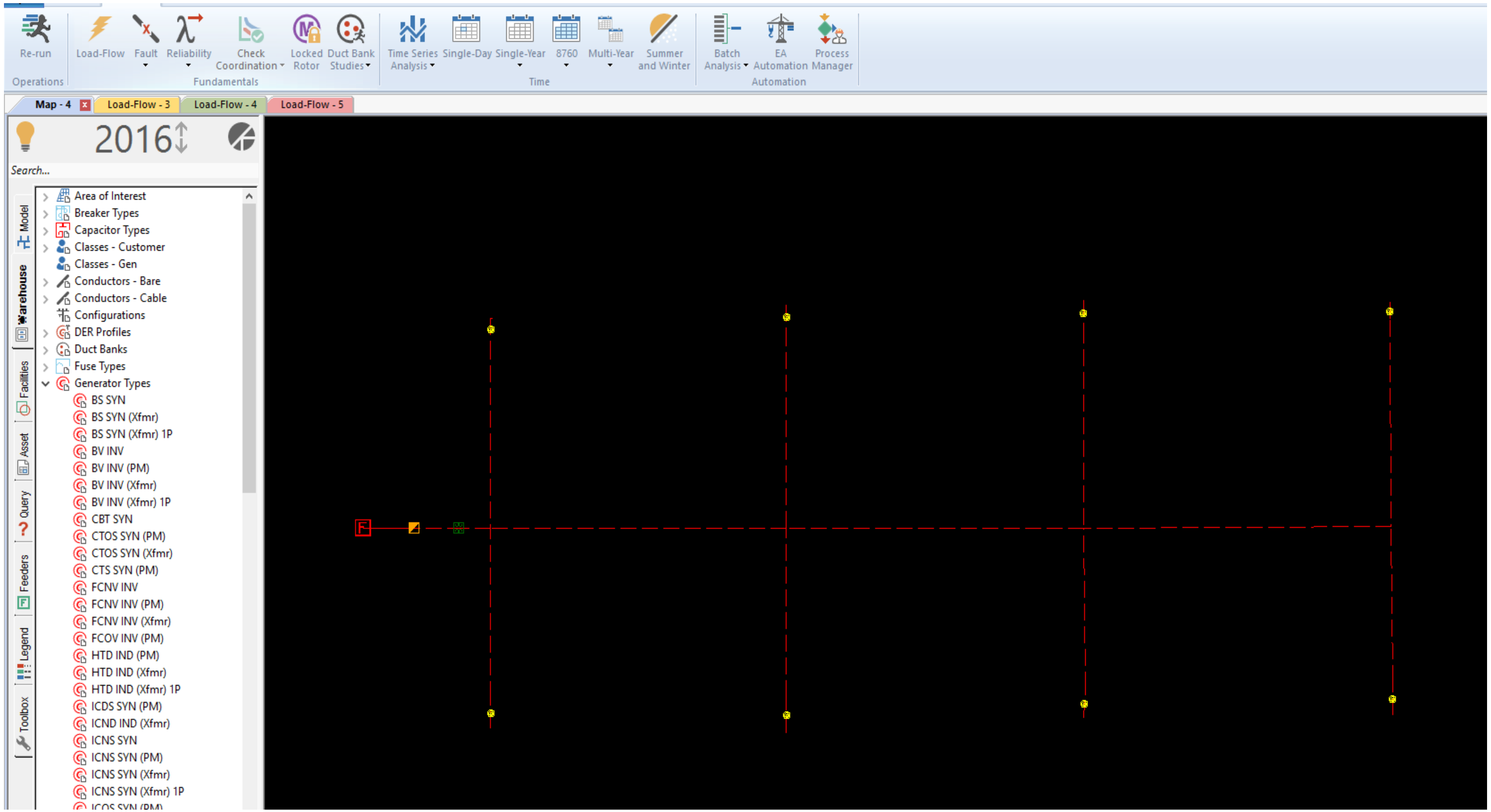
- When deploying generating DERs on the secondary network, network losses may increase or decrease depending on the coincidence of generation with load.
- Load reducing resources like that of EE or DR will always serve to reduce losses on the secondary network.

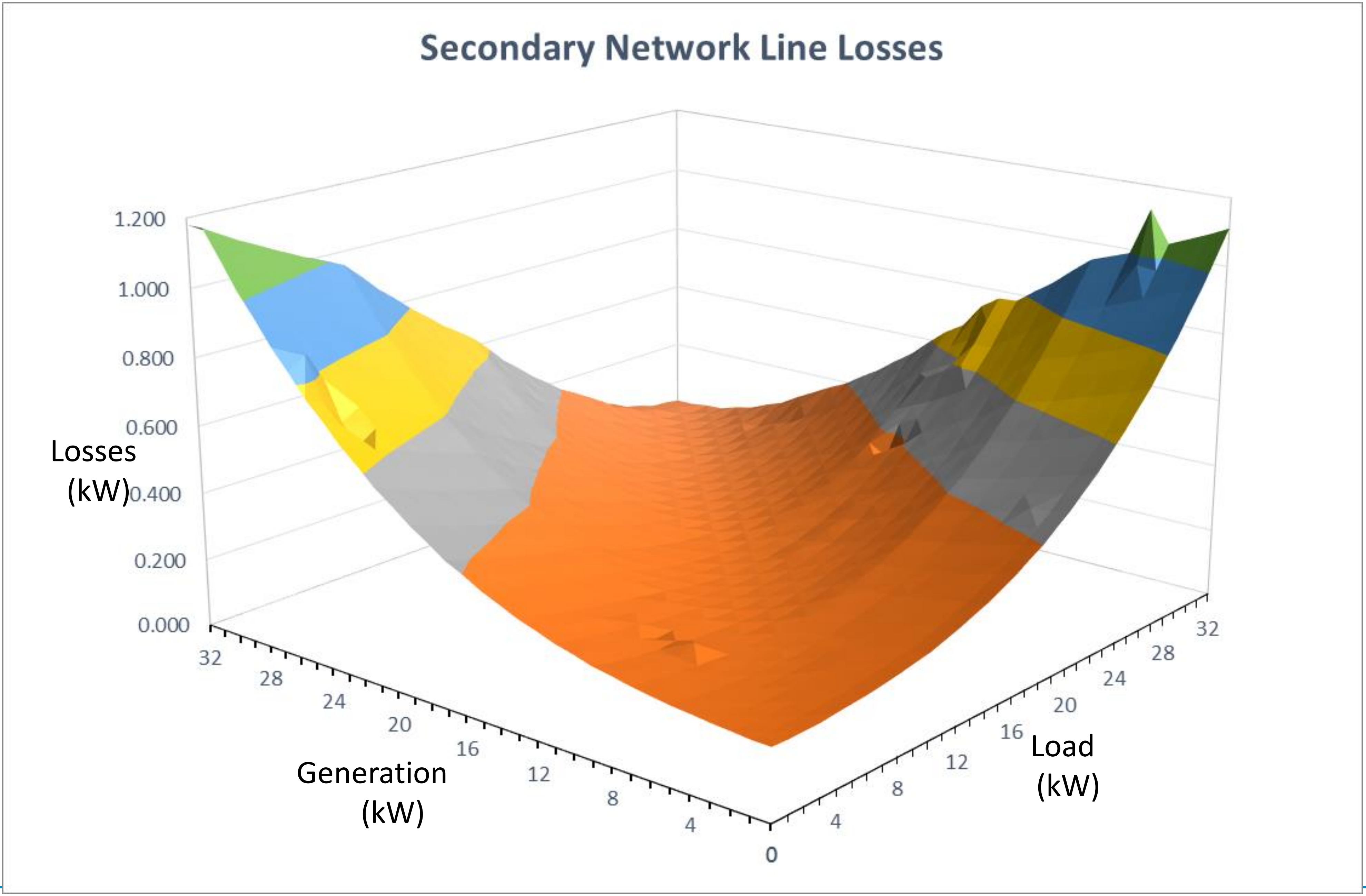
Secondary Line Losses

- There are many variables that will alter line losses on secondary networks.
  - Three phase/ Single Phase
  - Single phase line to ground/line to line
  - 120/240/208/480 Voltage levels etc.
  - Transformer(s) kVA, type, impedance, tap setting
  - Conductor type, length, and configuration
  - Number of customers, load profiles
  - DERs

- Design standards serve to optimize secondary network configuration to provide electric service in the most economic way over time (taking losses into account)

Secondary Line Loss Model

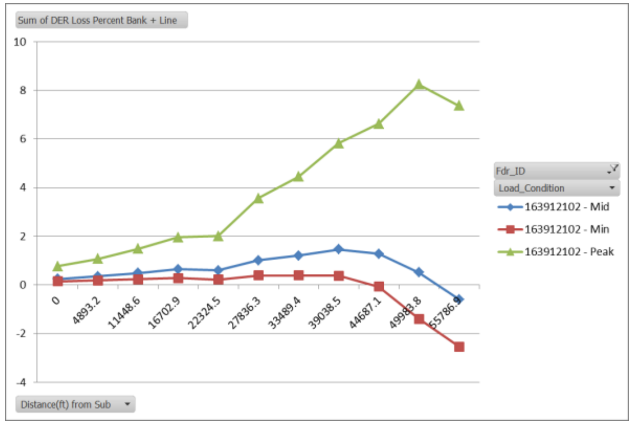


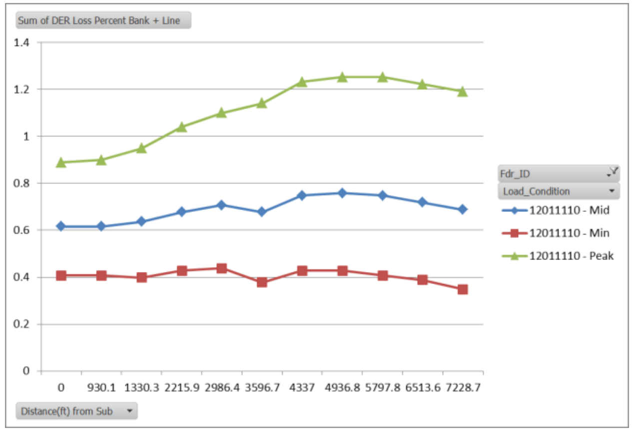


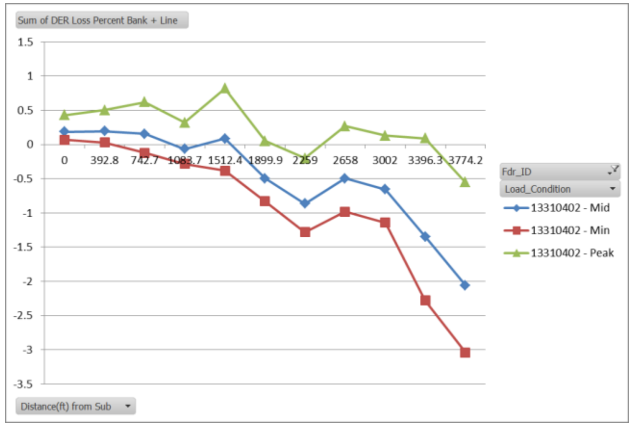
Secondary Network Line Losses
1.200
1.000
0.800
0.600
0.400
0.200
0.000
Losses
(kW)
32
28
24
20
16
12
8
4
0
Generation
(kW)
4
8
12
16
20
24
28
32
Load
(kW)

PG&E – Line Loss Study

- 15 Representative Circuits
- Modeled 1 MW DER at various points along feeder under peak, mid and minimum load conditions
- Modeled locations at main line as well as three-phase branches
- PG&E system is very diverse:
  - Rural feeders tend to be longer, and have more locations with high peak losses.
  - Backfeeding does cause losses to increase in certain locations
  - Urban feeders have low losses and are not highly location sensitive



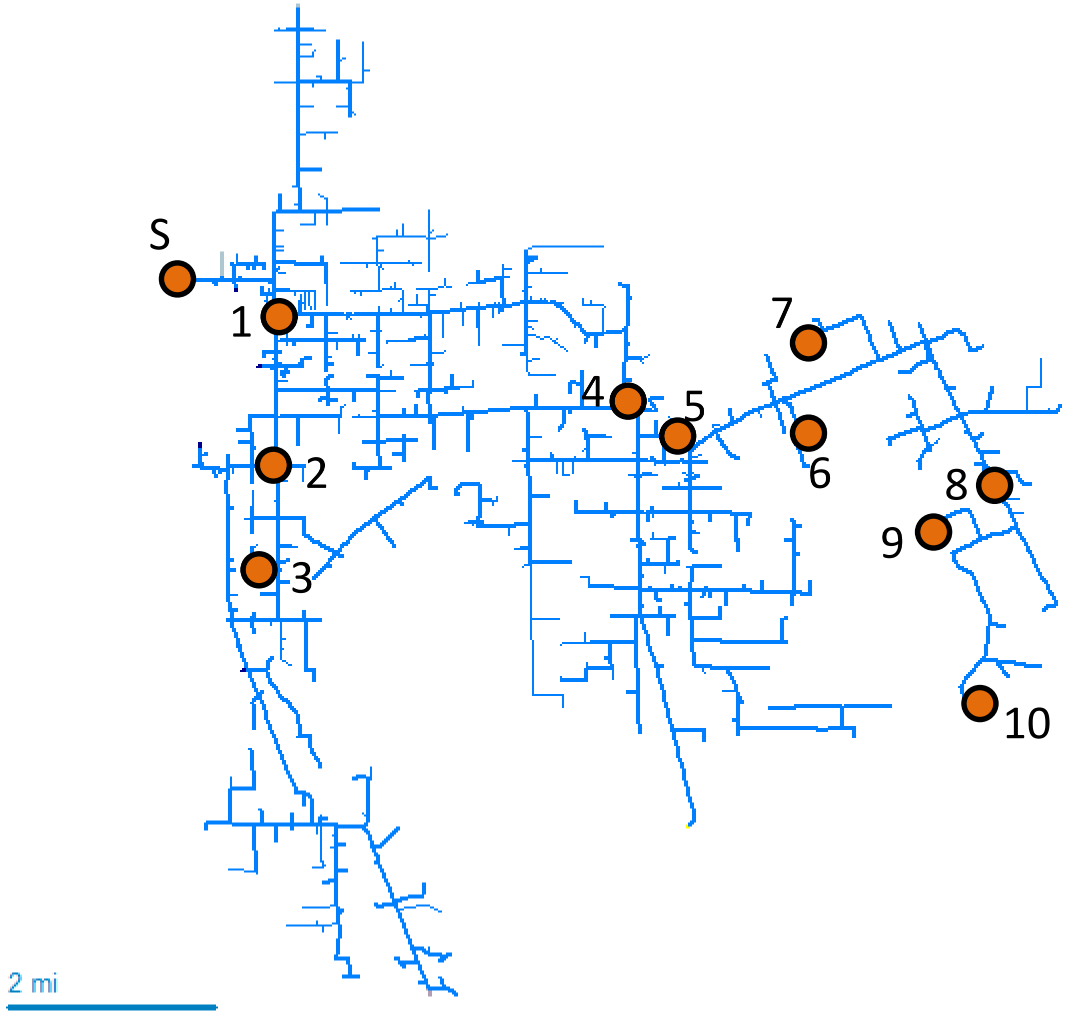




PG&E – Line Loss Study Examples

Node	Loss Factor
S	0
1	0.0252
2	0.0486
3	0.0455
4	0.1672
5	0.1904
6	0.1926
7	0.1933
8	0.2122
9	0.1971
10	0.190

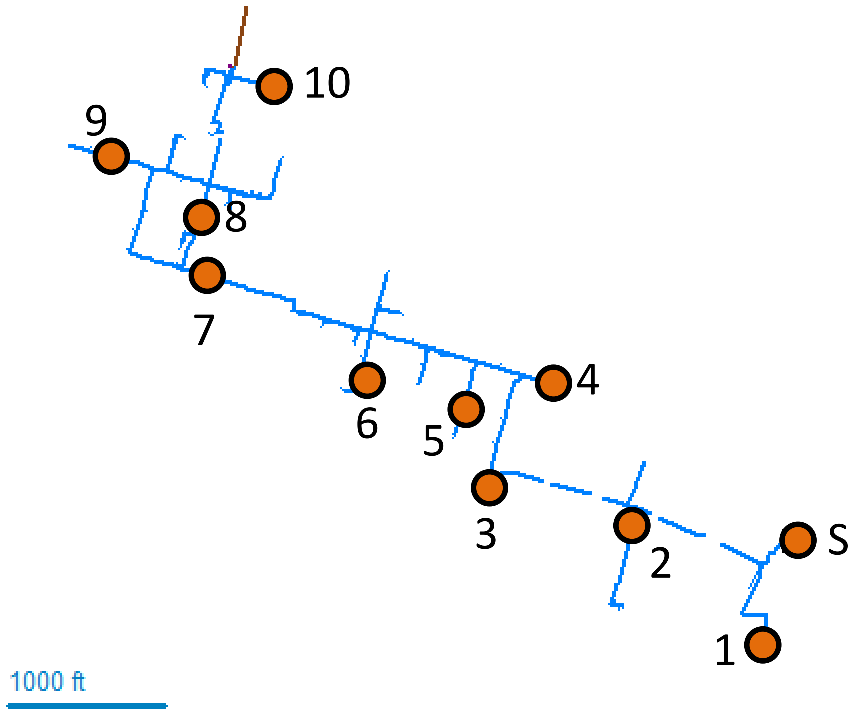
Corning 1104, 12 kV, Rural, Peak Load



PG&E – Line Loss Study Examples

Node	Loss Factor
S	0
1	0.0001
2	0.0006
3	0.0015
4	0.0021
5	0.0025
6	0.0034
7	0.0036
8	0.0036
9	0.0033
10	0.003

Oakland C 1110, 12 kV, Urban, Peak Load



Proposal for Locational Losses in LNBA

Cost Effectiveness Use Case in DERAC

- Maintain Status Quo in publicly available tool (DERAC).

Deferral Framework Use Case

- For each deferral opportunity, evaluate more granular locational losses
  - Variation in losses can be significant for "outlier" locations (e.g. at a location with 25% losses at peak, a 750 kW generator can provide 1 MW load reduction at the transformer)
  - Evaluation approach will depend on number of deferral opportunities and associated circuits that pass through deferral screens TBD in track 3
    - If a small number of feeders, more detailed modeling is feasible
    - If a large number of feeders, a clustering/representative feeder approach may be needed.
  - IOUs will incorporate preferred approach in 2018 roll out of LNBA heat map and public tool

Item 4.i – Locational Avoided Energy – Recap

- Item 4.i - “Incorporate additional locational granularity into Energy”
- IOU Proposal from the July Working Group Meeting:
  – Remove system-wide avoided energy values and replace with Default Load Aggregation Point (DLAP) forecasts for the three IOUs

Item 4.i – Avoided Energy – DLAP

- DLAP prices are what the IOUs pay to serve load to its customers
  - "Load is bid in and settled at the DLAP LMP as opposed to the nodal LMP."[1]
- DLAP prices represent the avoided cost of energy for the utility

1 "Load Granularity Refinements, Pricing Study Results and Implementation Costs and Benefits Discussion," CAISO, January 14, 2015, pg. 11.

Item 4.i – Avoided Energy – Exploring the Proposal

- Propose methodologies to forecast the DLAP prices
- IOUs approached E3 to provide initial analysis and explore methodologies

Energy+Environmental Economics

Locational Energy and Generation Capacity Avoided Costs

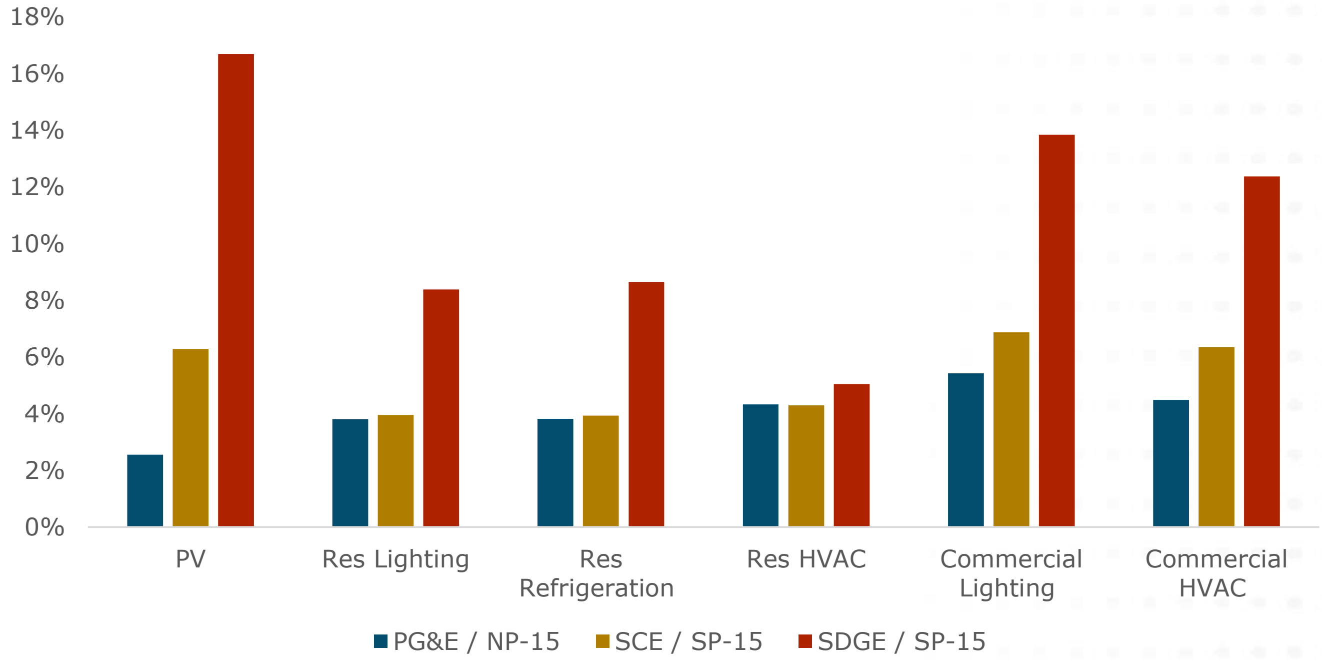
Brian Horii and Jack Moore

11/13/2017

Locational Energy Avoided Costs

Energy Avoided Costs

+ **Current avoided costs are hourly NP-15 and SP-15**
+ **SP-15 does not adequately reflect SDG&E and SCE cost differences**



Avoided Energy Cost Disaggregation Level

+ SCE SLAP vs DLAP Value

	PV	Res Lighting	Res Refrigeration	Res HVAC	Commercial Lighting	Commercial HVAC
Core (SCEC)	-1.3%	-0.6%	-0.6%	-0.6%	-0.8%	-0.8%
SCE West (SCEW)	3.9%	2.3%	2.3%	2.7%	2.7%	3.0%
SCE North (SCEN)	-3.4%	-2.6%	-2.2%	-1.0%	-2.6%	-2.1%
SCE Northwest (SCNW)	-3.0%	-3.5%	-3.0%	-2.2%	-2.4%	-2.5%
SCE High Desert (SCHD)	-9.2%	-3.5%	-3.8%	-5.0%	-4.9%	-5.8%
SCE Low Desert (SCLD)	-9.2%	-3.5%	-3.8%	-5.0%	-4.9%	-5.8%

PG&E SLAP vs DLAP

	Region	PV	Res Lighting	Res Refrigeration	Res HVAC	Commercial Lighting	Commercial HVAC
Central Coast (PGCC)	SLAP - PGCC	4.3%	2.3%	2.0%	0.3%	3.4%	2.7%
East Bay (PGEB)	SLAP - PGEB	1.7%	-0.2%	-0.2%	2.6%	0.6%	1.5%
Fresno (PGF1)	SLAP -PGF1	2.1%	5.4%	6.3%	7.6%	3.7%	3.7%
Geysers (PGFG)	SLAP - PGFG	-0.3%	-1.0%	-1.4%	-1.0%	-0.9%	-0.6%
Humboldt (PGHB)	SLAP - PGHB	9.4%	6.0%	6.6%	1.8%	8.0%	6.5%
Los Padres (PGLP)	SLAP - PGLP	-9.9%	-3.6%	-3.8%	-1.1%	-6.1%	-5.8%
North Bay (PGNB)	SLAP - PGNB	-0.1%	-1.0%	-1.2%	-0.9%	-0.6%	-0.4%
North Coast (PGNC)	SLAP - PGNC	0.5%	-1.4%	-1.5%	-0.4%	-0.8%	0.1%
North Valley (PGNV)	SLAP - PGNV	-4.1%	-5.1%	-4.9%	-5.7%	-4.6%	-4.7%
Peninsula (PGP2)	SLAP - PGP2	3.2%	1.3%	1.1%	0.6%	2.1%	2.2%
Sacramento Valley (PGSA)	SLAP - PGSA	-4.1%	-5.1%	-4.9%	-5.7%	-4.6%	-4.7%
San Francisco (PGSF)	SLAP - PGSF	5.7%	3.1%	2.9%	2.8%	3.9%	4.4%
San Joaquin (PGSN)	SLAP - PGSN	-4.1%	-5.1%	-4.9%	-5.7%	-4.6%	-4.7%
Sierra (PGSI)	SLAP - PGSI	-3.0%	-4.3%	-4.2%	-3.6%	-3.7%	-3.3%
South Bay (PGSB)	SLAP - PGSB	2.6%	0.7%	0.5%	-0.3%	1.5%	1.5%
Stockton(PGST)	SLAP - PGST	-0.9%	-2.6%	-2.5%	-1.5%	-1.9%	-1.3%

Energy Avoided Cost Forecasting

+ Current Process

- Energy avoided costs based on full cost of a CCGT less capacity market revenues
- Hourly shape based on 2015 hourly prices with shape adjustments based on the RPS Calculator

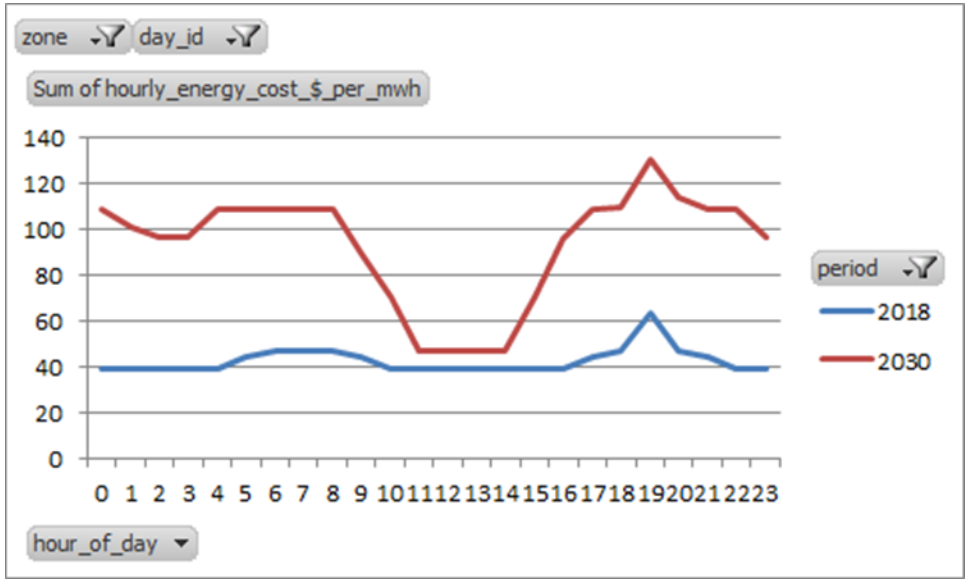
+ Future Process

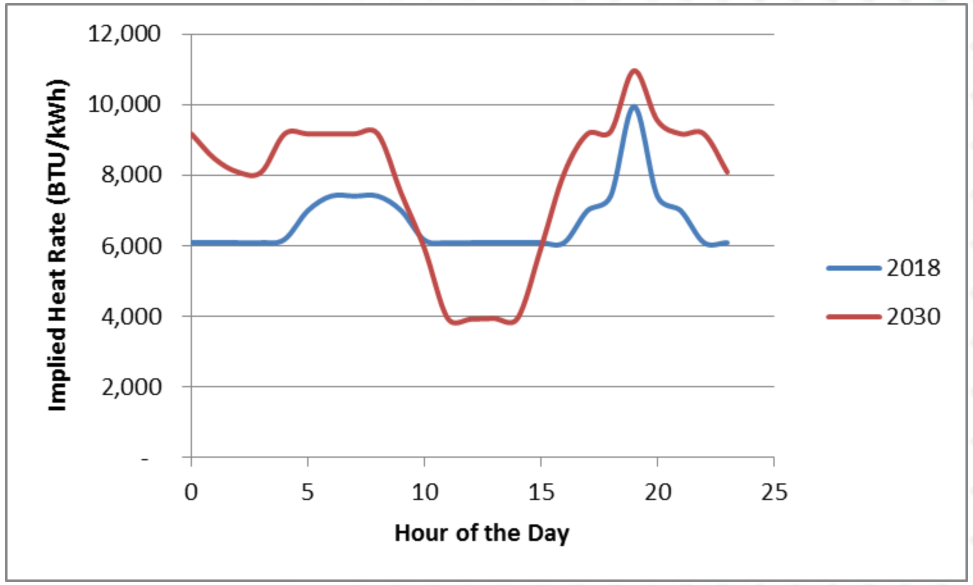
- Use Production Simulation models
- Use proxy method

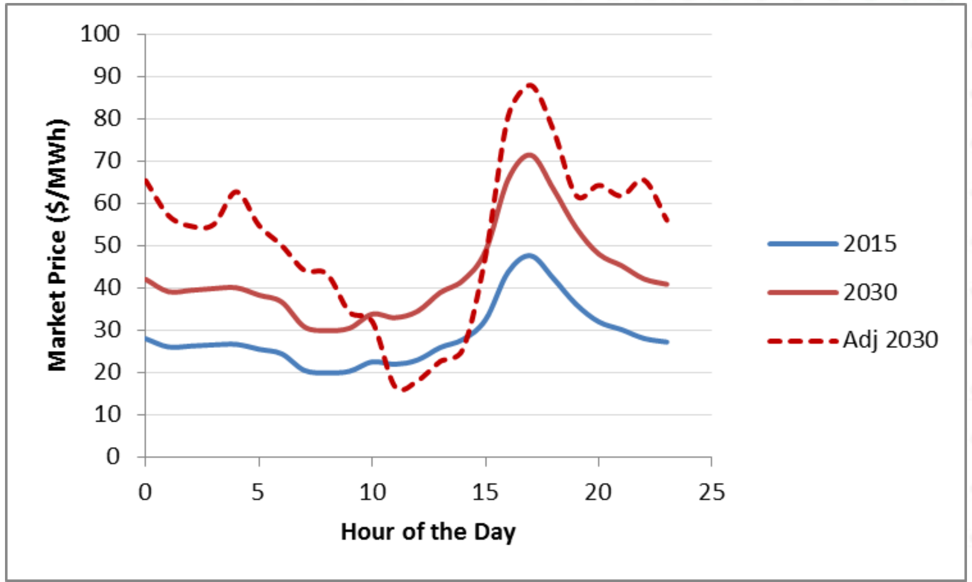
Proxy Method

+ **Use results from RESOLVE modeling in the CPUC IRP proceeding**
    - Set annual average price level based on changes in average heat rates
    - Set shape based on changes in RESOLVE daytype

RESOLVE DayType Adjustments





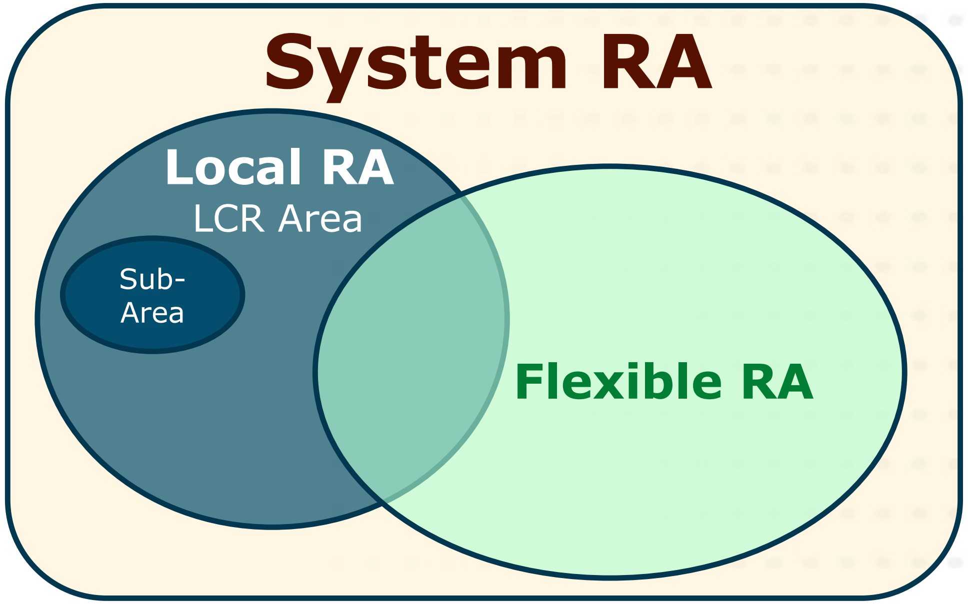


Avoided Capacity Costs

Avoided Capacity Costs

+ **California's resource adequacy (RA) program requires load serving entities (LSEs) to procure <u>three</u> types of overlapping capacity for year-ahead compliance purposes:**

- **<u>Local RA</u>: based on CAISO's 1-in-10 load, N-1-1 power flow studies for transmission constrained or local capacity requirements (LCR) areas that may have one or more binding sub-areas**
- **<u>Flexible RA</u>: based on annual CAISO study that looks at largest 3 hour ramp in each month (updates pending)**
- **<u>System RA</u>: requirement calculated based on California Energy Commission (CEC) load forecast + 15% planning reserve margin for entire system**



Local Capacity is more heavily constrained in certain regions

- **CAISO currently projects LCR needs and capacity (NQC) for 2018, 2022, and 2026 periods**
  - Also can be constrained sub-areas within LCR zones
- **Projection reflects changes to local load within LCR pocket, local generation & DER, and transmission constraints under contingency conditions**
- **Some zones projected to more capacity than needed while others have potential deficiencies (e.g., Stockton for 2018)**
- **Transmission upgrades to a local area or local generation/DER could remedy shortages**

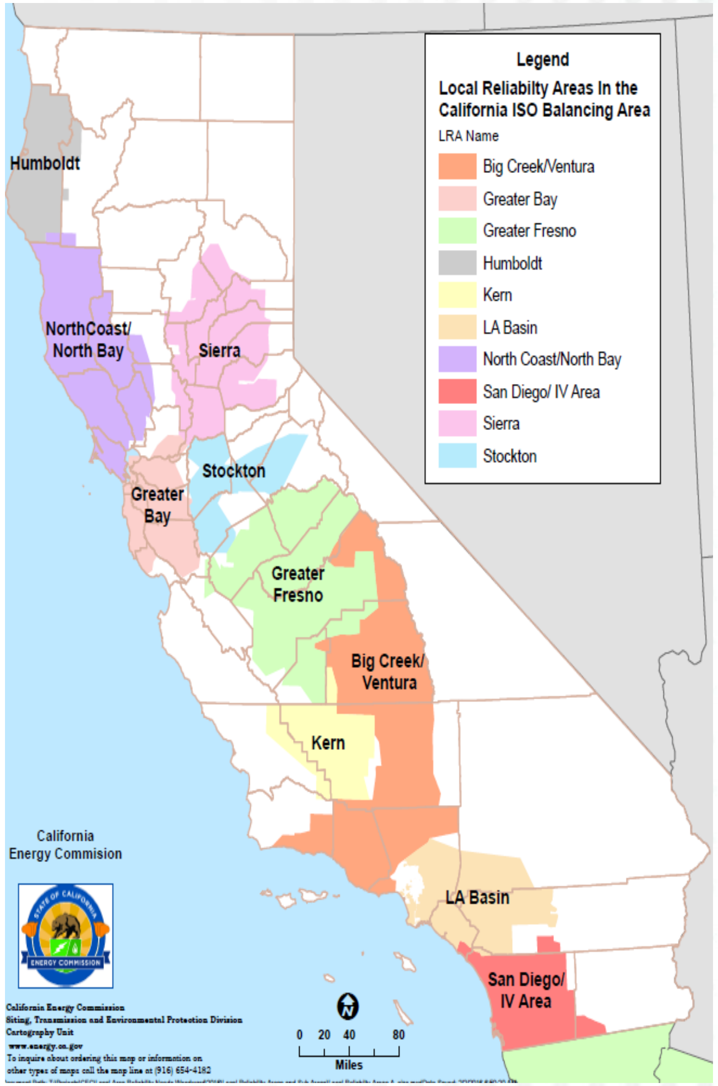
2018 Local Capacity Requirements

	Qualifying Capacity			2018 LCR Need Based on Category B***			2018 LCR Need Based on Category C*** with operating procedure		
Local Area Name	QF/ Muni (MW)	Market (MW)	Total (MW)	Existing Capacity Needed	Deficiency	Total (MW)	Existing Capacity Needed**	Deficiency	Total (MW)
Humboldt	14	196	210	121	0	**121**	169	0	**169**
North Coast / North Bay	118	751	869	634	0	**634**	634	0	**634**
Sierra	1176	949	2125	1215	0	**1215**	1826	287*	**2113**
Stockton	139	466	605	358	0	**358**	398	321*	**719**
Greater Bay	1008	6095	7103	3910	0	**3910**	5160	0	**5160**
Greater Fresno	364	3215	3579	1949	0	**1949**	2081	0	**2081**
Kern	15	551	566	0	0	**0**	453	0	**453**
LA Basin	1556	9179	10735	6873	0	**6873**	7525	0	**7525**
Big Creek/ Ventura	430	5227	5657	2023	0	**2023**	2321	0	**2321**
San Diego/ Imperial Valley	202	4713	4915	4032	0	**4032**	4032	0	**4032**
Total	5022	31342	36364	21115	0	**21115**	24599	608	**25207**

Example from CAISO 2018 Local Capcity Technical Report
https://www.caiso.com/Documents/Final2018LocalCapacityTechnicalReport.pdf

Incorporating Locational Value of Capacity

+ **Capacity contracts (including for meeting LCR needs) are determined through bilateral negotiations & Prices can vary a range of reasons (technology, vintage, location, etc.)**
+ **RA prices can vary significantly for projects in different LCR zones**
+ **Potential approach:**
  - Use historical FERC & other contract data for projects in different LCR zones to estimate proxy price for resources that could contribute capacity (NCQ) in those zones
  - Consider future load, resource, and transmission plans for these areas to identify potential capacity value in future, priced based on cost of alternatives (which could be cost of new entry for gas generator or other resources if gas not an available option)



Energy Forecast

Energy price forecast options

Many different potential models each have pros & cons, including different levels of effort needed to reflect IRP or to identify regional cost differences

Potential Options:

+ **Aurora Model updated to reflect IRP compliant inputs**
+ **PLEXOS case updated to reflect IRP compliant inputs**
  - Could start with CEC PLEXOS case (used for IEPR), or CAISO 2026 case
+ **CAISO Gridview Case used for TPP**
+ **Regression based approaches using historical data**
+ **RESOLVE model shape changes**

LNBA Item 8: Unplanned Grid Needs

IOU discussion points from October:

1. The IOUs do not believe it is appropriate to asses DERs at any one location for deferring unplanned grid investments as the risk of overpaying for DER services outweighs the small number of unplanned grid investments that will likely arise
2. The IOUS will attempt to limit the possibility of unplanned grid investments by continuing to refine the forecasting process and potentially shorten the presumed window of DER implementation through the Demo C process
3. The IOUs can track the number and $ of unplanned capacity investments going forward to better understand the dollar value associated with unplanned grid investments.
4. For value beyond 10 years: Assess DERs for T&D value beyond then planning horizon at a later time such that they may be continually incentivized to remain online if value still exists in a later iteration of the planning forecast.

LNBA Item 8: Unplanned Grid Needs

- CALSEIA proposal on unplanned grid needs
  - Not all new capacity projects (outside of large spot capacity needs) are planned – may not apply to voltage-related projects.
  - Question: what is the pace with which projects move from needs to identified projects? If a project is clearly identified and planned for construction 3-5 years in the future, utilities could run a DER solicitation to defer the project. However, this does not cover all of the benefits of DERs delaying upgrade needs

LNBA Item 8: Unplanned Grid Needs

As the LNBA moves beyond creating tools for deferral solicitations to measuring locational benefits of DERs, it must take into account the benefits of:

- Delaying upgrades that have been generally identified but not specifically planned.
- Delaying upgrades beyond the 10-year planning horizon.
- Providing flexibility for upgrades under development.
- Deferring the need for voltage-related upgrades.

LNBA Item 8: Unplanned Grid Needs

- To measure the extent to which upgrades proceed erratically through the planning process, the utilities could make two calculations.
  - First, determining how many constructed projects were in the planning process for less than ten years would give an indication of the portion of projects that were not candidates for deferral solicitations due to timing.
  - Second, determining how many projects have remained in planning documents longer than ten years would give an indication of what portion of projects were delayed due to DER adoption and other changes in forecasted load growth.

MORE THAN SMART

Items 8&9: Unplanned Grid Needs

- ACR Group III, Item 8:
  - "Develop a methodology to quantify the likelihood of an unplanned grid need (deferrable project) emerging in a given location
- ACR Group III, Item 9:

  "Value locational value of DERs beyond 10 years "
- For Both Items 8 & 9:
  - "[Should be considered the same] as valuing unplanned grid needs encompasses long-term (>10-year) grid needs. However, such values are speculative and likely difficult to quantify for practical use in the LNBA

Item 8: Unplanned Grid Needs within Horizon

- Capacity projects, the primary distribution service type subject to deferral by DERs, by their nature do not typically result from "unplanned needs" the IOU load addition process is set up to have visibility of capacity needs long before they arise due to typical load growth.
- The majority of unplanned needs that could arise in a short time periods are due to large spot load additions that either force the utility to construct voltage or capacity projects to accommodate new load in a short period of time i.e. new large water pumps, casino, high rise, manufacturing facility, etc.

Item 8: Unplanned Grid Needs within Horizon

- The IOUS as regulated utilities are obligated to provide capacity service for new interconnections within a “reasonable amount of time” SDG&E currently targets limiting time of interconnection of any load to be less than 2 years.
- The IOUs strongly believe in the societal economic benefits of getting a new load online as soon as possible and believe the interconnection process should not be slowed it down in anyway.
- Considering loads that drive unplanned grid needs are usually particularly large it would be difficult to stimulate DER market activity fast enough to meet such large needs in such a short timeframe.

Item 8: Unplanned Grid Needs within Horizon

- Many of the large spot load needs driving utility projects are also grid edge projects where the new load is in a location with absolutely no existing infrastructure. In these locations usually some type of utility project will be required regardless to establish grid connectivity.
- For grid connectivity projects the incremental cost of building extra capacity to accommodate future load growth is minimal so planners usually use these projects to optimize around potential future capacity needs.

Unplanned Grid Needs within Horizon

- The overwhelming barrier to entry from using DERs to address unplanned grid needs will most likely be timeframe.
- Given such a short time window to address a new need its seems impractical to rely on any type of passive incentive mechanisms to deploy DERs in a area to offset an unplanned project of any kind. It is likely some utility driven solicitation would be the only way to bring about a DER alternative to unplanned grid need.
- Demo C will shed light on the timeframe required to solicit for DERs as well as various DER type deployment timeframes

IOU Recommendation for Assessing DERs for Meeting Unplanned Grid Needs

1. The IOUs do not believe it is appropriate to asses DERs at any one location for deferring unplanned grid investments as the risk of overpaying for DER services outweighs the small number of unplanned grid investments that will likely arise
2. The IOUS will attempt to limit the possibility of unplanned grid investments by continuing to refine the forecasting process and potentially shorten the presumed window of DER implementation through the Demo C process
3. The IOUs can track the number and $ of unplanned capacity investments going forward to better understand the dollar value associated with unplanned grid investments.

Item 9: Grid Needs Beyond 10 Years

- The majority of system level benefits provided via DERs are already accounted for beyond 10 years and included in the LNBA tool. Any load reductions a DER may be provide is weighed against the forecasted price of system level values for Energy, emission, etc for the DERs assumed lifetime of the DER in the tool.
- The only benefit not included beyond 10 years are T&D values
- IOUs remain adamant that grid needs beyond 10 years are not reflected in the initial assessment of a DER on the grounds that forecasting grid needs beyond 10 years is a highly speculative.

Item 9: Grid Needs Beyond 10 Years

- The IOUs however acknowledge T&D value will absolutely still exist in years 10 + so long as a T&D project would still be needed without the DER providing capacity service at that time.
- It is for this reason the IOUs believe we should weigh or assess that value at the time of need rather than speculate on what the value could be thereby limiting the risk to ratepayers for valuing a service that may never be provided.
- This also protects ratepayers from entering contractual obligations that could result in them substantially overpaying for a service as result of reduced DER costs over time. (similar to many PV contracts signed by thee IOUS in the beginning of the RPS mandates)

IOU Recommendation for Grid Needs Beyond 10 Years

1. Assess DERs for T&D value beyond then planning horizon at a later time such that they may be continually incentivized to remain online if value still exists in a later iteration of the planning forecast.