PWP 2015 IRP – EXHIBIT 6

ASSESSMENT OF DISTRIBUTION LEVEL INTEGRATION COSTS FOR DISTRIBUTED PV

B&V PROJECT NO. 184915

PREPARED FOR

Pasadena Water & Power

11 FEBRUARY 2015

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1. Overview of Distributed PV Issues

As part of its 2014 Integrated Resource Plan (IRP) process, Pasadena Water & Power (PWP) requested that Black & Veatch perform a study to compile information on the grid impacts of solar photovoltaic (PV) installed on the distribution system, including lessons learned from previous studies and specific cost estimates published that are relevant to PWP. The purpose is to inform PWP about the consequences of increasing PV penetration on its distribution system so that it can make intelligent decisions about the amount and location of future distributed PV deployment. (This study includes solar PV installations on the customer side of the meter as well as utility-side installations on the distribution system.) The report is organized as follows:

- **Section 1** provides an overview of distributed PV issues, including PV market growth, potential impacts on the distribution system, mitigation solutions for these impacts, and a summary of PWP's experience with distributed PV interconnection.
- **Section 2** describes the purpose, methodology and results from a number of recent public reports by research teams and utilities on the topic of distributed PV grid integration.
- **Section 3** provides a summary of the analytical approaches, the key findings, and the cost estimates from these studies, suggests directions for future PWP-specific studies, and lists high-level conclusions.

MARKET GROWTH

Over the past 15 years, distributed PV has experienced tremendous growth across the U.S. and especially in California. Figure 1-1 shows the growth of behind the meter distributed generation (DG) in California since 1998. Non-solar types of DG have experienced slow and steady growth and they make up around ten percent of the total installed capacity as of 2014, but distributed PV has seen exponential growth and reached over 3,000 MWac as of the end of 2014.

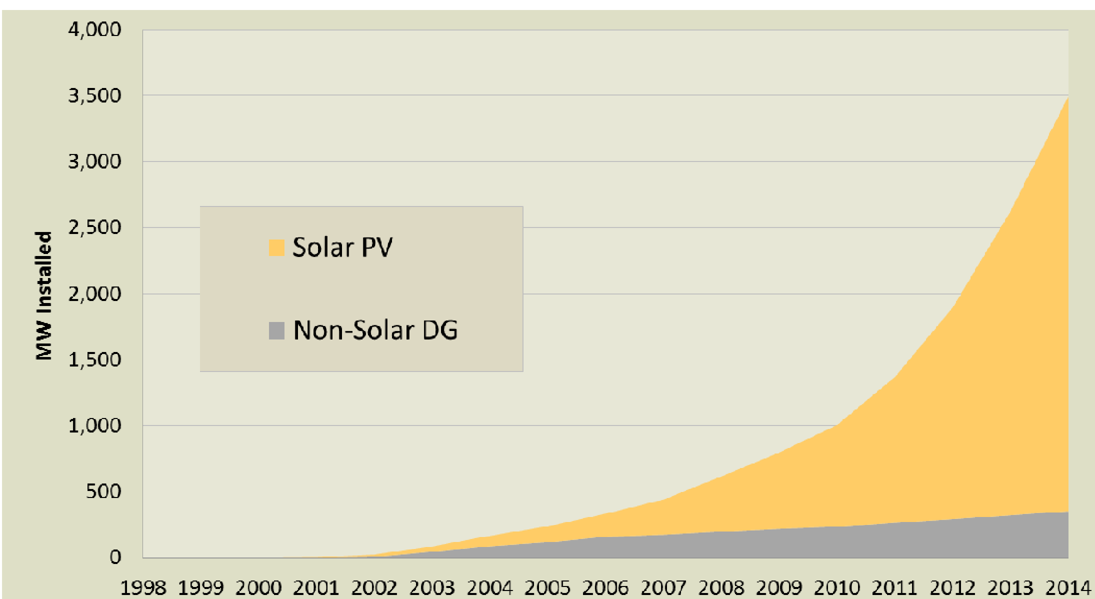

Figure 1-1 Growth of Behind the Meter DG in California, 1998-2014[1]

While state incentives under the California Solar Initiative (CSI) and other programs have historically driven this growth in distributed PV, in 2014 the majority of behind the meter PV installations were

[1] Black & Veatch estimate based on historical state incentive program data and Greentech Media Research reports on installed PV capacity in 2012-2014.

completed without a state incentive (though they still used the 30 percent federal investment tax credit). This is largely because the CSI incentives have been exhausted, but it also demonstrates that PV is increasingly cost-effective for retail customers. Figure 1-2 shows that in the second quarter of 2014, only about 28 percent of residential California PV installations used a state incentive, down from 99 percent two years earlier.

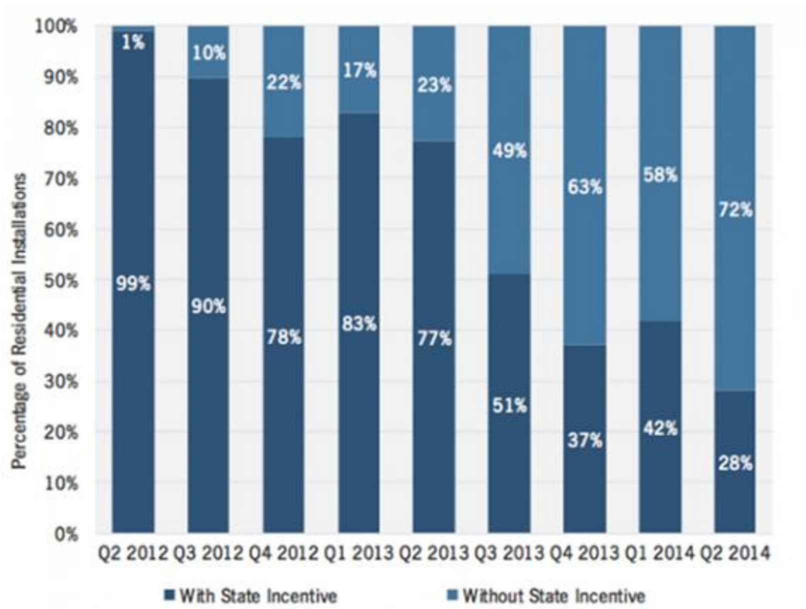

Figure 1-2 Percentage of California Residential PV Installations Using State Incentives, 2012-2014[2]

With the federal investment tax credit set to expire or significantly decrease at the end of 2016 (depending on the sector), many forecasts predict that PV installations will slow in 2017 but that growth will continue thereafter because the costs of PV will keep declining in comparison to retail electric rates. However, a number of other factors (including the reform of the net energy metering tariff under Assembly Bill 327) could also slow growth.

IMPACTS ON DISTRIBUTION SYSTEM

With this tremendous growth in distributed PV, impacts are expected on the electric distribution system. Academic researchers and utility engineers have performed a number of studies to identify and quantify these impacts, and determine at what penetration they become significant for utility operations. The potential negative impacts fall into five categories:

1) Thermal Impacts
    a. Exceeding equipment ratings for conductors and other components
2) Voltage Impacts
    a. Exceeding voltage limits (overvoltage or undervoltage)
    b. Interference with conservation voltage reduction (CVR) schemes
    c. Increase in load tap changer operations (and associated O&M cost increases)
3) Reverse Power Flow
    a. Effects on switching and feeder configuration
    b. Need for adjustment of equipment settings
    c. Exceeding substation transformer or breaker ratings

[2] http://www.greentechmedia.com/articles/read/the-legacy-of-the-california-solar-initiative

4) Protection Impacts
    a. Fault protection
    b. Phase imbalance at substation breakers
    c. Miscoordination of existing protection schemes
    d. Effects on existing under-frequency load shedding schemes
5) Power Quality Impacts
    a. Increased harmonics
    b. Resonance issues
    c. Increased voltage flicker
    d. Customer power factor impacts

To date, most of these impacts have been avoided through the interconnection process, during which utilities use various screens to decide whether a particular PV project can interconnect to the distribution system safely and whether system upgrades are required. However, impacts will become more substantial, and more difficult to avoid through the normal interconnection process, as PV penetration increases. It is also important to note that the PV hosting capacity, which is the amount of distributed PV that can be accommodated on a circuit, can vary greatly depending on a distribution circuit's characteristics.

PV can also create positive impacts on the distribution system. These benefits may include reduction of transmission and distribution line losses, reduction of peak demand on the transmission and distribution system, and deferral of distribution system upgrades due to peak load reduction. Non-technical benefits of PV are also well documented (e.g., reduction of air pollution and greenhouse gas emissions, and local economic development).

MITIGATION SOLUTIONS

A number of solutions are available to mitigate the potential impacts of distributed PV on the distribution system, and thereby increase the hosting capacity of a particular circuit or substation. Black & Veatch groups these into conventional and advanced solutions:

- Conventional Solutions
    - Adjustment of equipment settings
    - Additional voltage regulators
    - Additional capacitor banks
    - Additional switches and feeder ties
    - Additional transformers
    - Breaker upgrades
    - Additional protection devices or protection upgrades
    - Reconductoring
    - New feeders or substations
- Advanced Solutions
    - Curtailment of PV output
    - Distribution Management System (DMS) based switching
    - Energy storage (utility- or customer-owned)
    - Utility volt/VAR control
    - Smart inverter deployment (fixed power factor operation, volt/VAR or frequency/watt dynamic response, direct utility control)
    - Demand response (direct load control, price signals to customers, market-based)

Costs to deploy these mitigation solutions can vary by circuit. Many of the advanced solutions listed are still emerging and thus the efficacy and costs for those are much less certain than for the conventional solutions. The advanced solutions also depend greatly on individual utility plans to invest in new technologies, new control and communication networks, and new operational strategies.

PWP EXPERIENCE WITH DISTRIBUTED PV INTERCONNECTION

Black & Veatch consulted with PWP staff and received input on PWP's experience to date with integration of PV on its distribution system. This input indicated that PWP currently has approximately 6 MW of distributed PV installed in its service territory, which is equivalent to about two percent of PWP's peak load. PWP has not observed significant impacts from distributed PV on its distribution system so far, and no distribution equipment upgrades have been completed specifically to accommodate PV on a circuit.

Thus, it appears that the PWP DG interconnection process under Pasadena's Regulation 23 (which was modeled after the pre-2012 version of Rule 21, the interconnection process used by the California investor-owned utilities) has successfully avoided significant negative impacts from PV interconnecting to PWP's system. However, PWP's input also indicated that any impacts from PV, along with PV-related interconnection and distribution upgrade costs, are not systematically tracked. This makes it difficult to state conclusively that PV has not created any substantial impacts or costs, but given the lack of anecdotal evidence it is likely that any impacts and costs have been relatively minor.

2. Summary of Previous Reports

This section provides a summary of key reports including lessons learned and specific cost estimates that have been developed through research on the grid impacts of solar PV installed on the distribution system.

Summaries of the following reports have been included in this section:

- Distributed Generation Interconnection Plan, Hawaiian Electric Companies, August 2014.
- Duke Energy Photovoltaic Integration Study, Carolinas Service Areas, Pacific Northwest National Laboratory, Duke Energy, Alstom, March 2014.
- The Impact of Localized Energy Resources on Southern California Edison's Transmission and Distribution System, Southern California Edison, May 2012.
- Distributed Generation Integration Cost Study, Analytical Framework, Navigant Consulting Inc, California Energy Commission, November 2013.
- California Solar Initiative RD&D: High Penetration PV Integration Project: FY 13 Annual Report, National Renewable Energy Laboratory and Southern California Edison, June 2014.
- Stochastic Analysis to Determine Feeder Hosting Capacity for Distributed Solar PV, Electric Power Research Institute, December 2012.
- Technical Potential for Local Distributed Photovoltaics in California, Energy and Environmental Economics (E3) and California Public Utilities Commission (CPUC), March 2012.
- Verification of EnergyNet Methodology, California Energy Commission, December 2010.

DISTRIBUTED GENERATION INTERCONNECTION PLAN

Hawaiian Electric Companies (2014)

Purpose

To proactively mitigate operational constraints caused by high levels of DG penetration, the Hawaiian Electric Companies' Distributed Generation Interconnection Plan (DGIP) identifies specific circuit and distribution system upgrades required to enable higher levels of DG penetration in a proactive manner. The study includes a process to identify upgrades needed to increase circuit interconnection capability in capacity increments through the Distributed Generation and Interconnection Capacity Analysis (DGICA). Specific strategies and actions, including costs and schedules, for circuit upgrades are included in the Distribution Circuit Improvement Implementation Plan (DCIIP).

Methodology

For the DGICA, representative circuit penetration studies were performed to determine allowable distributed PV limits for the Companies' distribution systems. This approach included system analysis with steady state and dynamic studies to determine system level constraints at high DG penetrations. Circuit level analysis was also completed to determine expected local impacts of issues related to reverse power flow to the distribution substation.

The DCIIP focused on analyzing the costs and benefits of proposed mitigation strategies developed to address interconnection constraints identified through the DGICA. In evaluating each company's projected load and DG, a base case cost model was developed for distribution level improvements for the short term (2014-2016), mid-term (2017-2020) and long term (2021-2030). The circuit and substation capacity analysis and base cost model compare existing and projected loads with DG penetration and identify constraints on circuits and substation transformers. The study identified a set of violations that triggered specified upgrades and associated unit costs (shown in Table 2-1), and upgrades were then applied in the year of anticipated violations.

Table 2-1 Hawaiian Electric Distribution Upgrade Unit Costs

ITEM	VIOLATION TRIGGER	UNIT COST
Regulator	Feeder Reverse Flow	$10,000
Load Tap Changer	Substation Transformer Reverse Flow	$10,000
Reconductoring	Exceed 50% Backbone Conductor/ Cable Capacity	$1,100,000 OH/ $4,300,000 UG per mile
Substation Transformer and Switchgear	Exceed 50% Capacity	Varies
Distribution Transformer	Exceed 100% Loading, % GDML Linear Relationship to % Transformers Upgraded	Varies
Poles and Secondary	Assumed 15% Distribution Transformer Replacements Include Pole Replacement	Varies
Grounding Transformers	Exceed 33% GDML for Maui Electric Exceed 50% GDML for 46 kV Lines	$60,000 for Maui $947,000 for Oahu

Results

The DGICA reported load growth and DG growth estimates for each company and included total existing and projected DG capacity availability for each Company, along with total upgrade costs (shown in Table 2-2).

Table 2-2 Hawaiian Electric Total Costs

ITEM	2016	2020	2030	CUMULATIVE TOTAL
Installed DG (MW, all three Companies)	547	677	902	902
PV Penetration (Percent)*	35	45	60	60
Regulator	$187,000	$55,000	$66,000	$308,000
Load Tap Changer	$912,000	$264,000	$466,000	$1,642,000
Reconductoring	$0	$0	$75,588,700	$75,588,700
Substation Transformer and Switchgear	$2,541,000	$2,475,000	$49,750,000	$54,766,000
Distribution Transformer	$4,462,164	$4,386,633	$6,768,738	$15,617,535
Poles and Secondary	$1,016,605	$993,371	$1,523,365	$3,533,342
Grounding Transformers	$33,033,000	$6,095,100	$3,917,100	$43,045,200
Total	**$42,151,769**	**$14,269,104**	**$138,079,903**	**$194,500,777**

Per-unit costs were calculated for each time period and are included in Table 2-3.

Table 2-3 Hawaiian Electric Per-Unit Costs

ITEM	2014-2016	2016-2020	2020-2030	AVERAGE (2014-2030)
Incremental DG (MW)	247	130	225	602
PV Penetration (Range from Start Year to End Year in Percent)*	20 – 35	35 – 45	45 – 60	20 – 60
Regulator ($/kW)	1	0	0	0
LTC ($/kW)	4	2	2	2
Reconductoring ($/kW)	0	0	336	84
Substation Transformer and Switchgear ($/kW)	10	19	221	61
Distribution Transformer ($/kW)	18	34	30	17
Poles and Secondary ($/kW)	4	8	7	4
Grounding Transformers ($/kW)	134	47	17	48
Total	**171**	**110**	**614**	**323**

*The PV penetration percentages reported in Table 2-3 are on a capacity, i.e., they are equal to the nameplate PV capacity divided by the expected system peak load. Penetration values on an energy basis are typically lower for PV than on a capacity basis, due to the expected annual capacity factor of solar PV production.

Figure 2-1 (taken from the Hawaiian Electric Companies' DGIP) summarizes the cumulative estimated costs of recommended system upgrades and a forecast of installed DG in the short-, medium, and long-term.

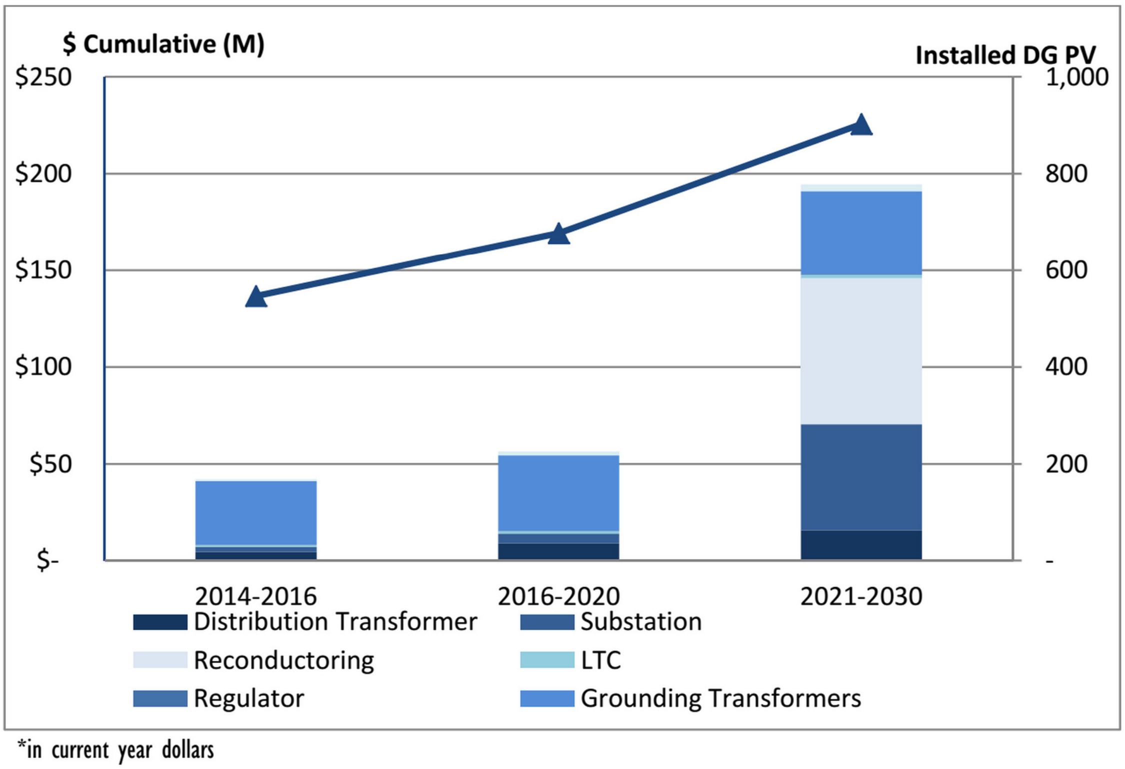

Figure 2-1 HECO DGIP Estimated Cumulative DG Integration Costs, 2014-2030

Furthermore, the study reported that the transient overvoltage threshold and thermal limits from reverse power flow are the primary factors that limit a circuit's ability's to integrate DG. The study focused primarily on conventional mitigation solutions to achieve projected DG PV adoption levels. A number of advanced mitigation solutions may be considered as the grid evolves and changes, including some of those listed above in Section 1.

DUKE ENERGY PHOTOVOLTAIC INTEGRATION STUDY, CAROLINAS SERVICE AREAS

Pacific Northwest National Laboratory, Duke Energy, Alstom (2014)

Purpose

The decreasing cost of solar PV, and the North Carolina Senate Bill 3 (SB3) mandate which established renewable energy goals for the state's utilities, means that increasing levels of solar PV are likely to be installed in the Duke Energy service territory. In anticipation of increased installation of PV, Duke Energy initiated this study as a first attempt to identify areas of concern and inform decisions establishing PV interconnection requirements and future resource plans.

Methodology

Two approaches were taken to study the impacts of distributed PV on the Duke Energy distribution system. The first approach was to conduct a system wide impact study at a 30 minute time step to determine impacts on technical losses, over/under voltage, and overloads. The second approach was to model a long rural feeder with an existing 5 MW PV plant located two miles from the substation under worst case conditions (low loading and high solar output and variability, with reverse power flow on the system) with a 3 minute time step to determine regulator tap changes and voltage impacts at a more granular level. For simulation, the scenarios ran on specified time interval (3 and 30 minute steps) taking into account load profiles, DG output schedules and local control device actions.

In the first approach, existing models of every feeder in the Duke Energy Carolinas territory were analyzed using Alstom DMS software to conduct power flow and fault calculations. In this study, solar projects were distributed across 461 out of 2,545 feeders and varied in size from 2 kW to 30 MW. Solar was installed only along the feeder backbone and projects were distributed evenly. A solar profile was developed for the system wide study based on the average production of seven monitored sites at 30 minute intervals during four seasons. Load profiles were based on 2012 peak days for summer and winter load cases, and 2012 lowest load days for fall and spring.

In the second approach, historical feeder data were used to determine the feeder flow at the substation for one feeder. Generator output for a single 5 MW plant was set to follow a schedule defined by historical SCADA data for the worst case condition day of an existing plant.

Results

The study did not quantify the interconnection and upgrade costs associated with installation of distributed PV on the distribution system. It did, however, estimate integration costs resulting from the additional reserves and cycling of conventional generators to compensate for PV variability to be on the order of $1.43 to $9.82 per MWh of PV energy depending on PV penetration levels (ranging from 2 percent in 2012 to 20 percent in 2022).

Conclusions resulting from the distribution analysis were qualitative in nature and confirmed that the net benefit of distributed PV is very dependent on feeder topology, penetration level and interconnection point. Overall, simulated distribution feeders experienced greater voltage fluctuations on feeders servicing PV installations; occasional reverse power flow was observed at higher penetration levels and regulation devices executed more voltage control actions. Equipment overloads tended to decrease, but in a few cases were caused by reverse power flow.

THE IMPACT OF LOCALIZED ENERGY RESOURCES ON SOUTHERN CALIFORNIA EDISON'S TRANSMISSION AND DISTRIBUTION SYSTEM

Southern California Edison (2012)

Purpose

The purpose of this study was to assess impacts of increasing penetration of local energy resources (or "LER" – largely distributed PV) on Southern California Edison's (SCE) distribution system under "unguided" and "guided" cases where policy instruments were used to guide installations from suboptimal rural areas to urban areas of high load. Through this assessment, SCE aimed to calculate average system wide costs for multiple types of installations and locations within the SCE electric system.

Methodology

Feeder analysis was completed for two urban and two rural feeders on the SCE system. PV build out was assumed to be distributed across feeders based on the percentage of projects installed in rural and urban areas under "guided" and "unguided" scenarios. Feeder level load flow analysis was conducted in CYME Dist for the four feeders under the two scenarios, and system impacts were reported for voltage issues, overloading issues and increased operations of voltage regulation equipment.

To calculate average system-wide costs for a 4,800 MW distributed PV policy goal, this study analyzed historical system impact studies of generators requesting interconnection to SCE's distribution system. Studies were divided by region, such that rural and urban projects were considered separately and average costs of upgrades per MW were determined for two categories: 1) distribution upgrades and 2) interconnection facilities. Average per-project costs were scaled up to calculate total system-wide cost estimates for both the guided and unguided cases.

Results

Through examination of 124 system impact studies, the estimates in Table 2-4 were developed:

Table 2-4 SCE Total Integration Costs

	UNGUIDED CASE		GUIDED CASE	
Location	Urban	Rural	Urban	Rural
Installed DG (MW)	1,440	3,360	3,360	1,440
Distribution Upgrades	$36,000,000	$705,000,000	$83,000,000	$302,000,000
Interconnection Upgrades	$270,000,000	$301,000,000	$630,000,000	$129,000,000
Total	$306,000,000	$1,006,000,000	$713,000,000	$431,000,000

Per-unit integration costs are included in Table 2-5, and are the same for the guided and unguided cases.

Table 2-5 SCE Per-Unit Integration Costs

	URBAN ($/KW)	RURAL ($/KW)
Distribution Upgrades	25	210
Interconnection Upgrades	188	90
Total	212	299

The average SCE per unit integration cost including distribution upgrades and interconnection facilities is $256/kW and corresponds to a distributed PV nameplate capacity penetration of 20 percent of SCE peak forecasted demand in 2020.

DISTRIBUTED GENERATION INTEGRATION COST STUDY

Navigant Consulting Inc., California Energy Commission (2013)

Purpose

In November 2013, Navigant Consulting Inc. issued a paper for the California Energy Commission entitled *Distributed Generation Integration Cost Study*. The object of the study was to verify work that SCE had previously completed to quantify integration costs on their system in May 2012 and to document an approach that could be applied by other utilities to produce sufficiently accurate integration cost estimates for a set of DG scenarios.

Methodology

System assumptions were defined to create study cases for evaluating DG integration costs. The study considered three DG penetration scenarios 1) baseline penetration of 4,800 MW evenly distributed 2) baseline penetration of 4,800 MW highly clustered and 3) 6,000 MW evenly distributed. For each scenario, variations on the percentage of projects to be sited in rural versus urban locations were tested at ratios of 30/70, 50/50, and 70/30.

To perform the analysis, 13 model feeders were selected for simulation to represent roughly 4,500 distribution feeders on SCE's system. A heuristic clustering technique was used to group feeders based on metrics, then, similarity was calculated between each feeder. The metrics used to evaluate feeder similarity were: number of residential customers, number of commercial customers, 3-phase line length, 1-and 2-phase line length, peak load, residential energy usage, commercial energy usage, line voltage and urban/rural designation.

For each scenario, model feeders were simulated in Milsoft and integration constraints were identified based on a set of distribution system performance standards. The performance criteria used to evaluate the simulation included: over/under voltage conditions, line or equipment overloads, excessive voltage regulation, reverse power, exceeded fault duty ratings, changes in protection coordination, operational constraints, power quality (voltage flicker) and additional SCADA or communication requirements.

Integration costs were composed of interconnection and upgrade costs. Upgrade solutions were identified to mitigate issues related to exceeded performance standards identified during simulation. Cost estimates were developed for the upgrades based on costs identified in the previous SCE study.

Navigant also calculated upgrade costs for the parametric studies (highly clustered PV and high penetration). For each performance violation accounted for in the Milsoft simulation, Navigant used existing SCE interconnection study results to identify the lowest cost mitigation solution. As such, integration upgrade costs are highly specific to the SCE system and scenario studied.

Table 2-6 shows the per unit upgrade costs used for each scenario of the Base Case study.

Table 2-6 Base Case (4800 MW of Distributed PV, 20 Percent Penetration) Unit Upgrade Costs

(ALL COSTS ARE $/KW)	70 % URBAN, 30 % RURAL	50 % URBAN, 50 % RURAL	30 % URBAN, 70 % RURAL
Voltage Regulation	13	13	17
Overhead Line Upgrades	61	83	120
Cable Replacements	0	0	0
New Feeder or Substation	0	0	0
Protection Upgrades	2	2	2
SCADA/Communications	2	2	2
Avg. Upgrade Integration Cost	77	100	140

Interconnection costs were based on available information from DG systems in the application queue and were assumed to be $101/kW for urban and $138/kW for rural.

Results

The calculated total and per unit integration costs are identified for each case study are identified in Table 2-7 below.

Table 2-7 SCE Total and Per Unit Integration Costs

CASE STUDY	70 % URBAN, 30 % RURAL	50 % URBAN, 50 % RURAL	30 % URBAN, 70 % RURAL
Base Case: Distributed, 4,800 MW, Cost ($)	$900,000,000	$1,075,000,000	$1,300,000,000
Base Case: Distributed, 4,800 MW, ($/kW)	188	224	271
Parametric: Clustered, 4,800 MW, Cost ($)	$1,250,000,000	$1,500,000,000	$2,000,000,000
Parametric: Clustered, 4,800 MW, ($/kW)	260	313	417
Parametric: Distributed 6,000 MW, Cost ($)	$1,200,000,000	$1,600,000,000	$2,000,000,000
Parametric: Distributed, 6,000 MW, ($/kW)	200	267	333
Note: 4,800 MW is equivalent to 20 percent PV penetration; 6,000 MW is equivalent to 25 percent PV penetration. PV penetration is calculated here as the installed nameplate PV capacity divided by the peak forecasted demand for SCE in 2020 (PV penetration on an energy basis would be much lower).			

The following were additional key findings and conclusions of the study:

- The integration cost of DG depends highly on location.
- Integration cost is typically lower when DG is installed in urban areas.
- Integration costs increase significantly as greater amounts of DG are clustered at the end of lines.
- New systems and processes may need to be implemented to achieve this level of PV by 2020.
- Potential changes could include automated control, revised system operating procedures, and policies to encourage DG development in areas with the lowest integration costs.

CALIFORNIA SOLAR INITIATIVE RD&D: HIGH PENETRATION PV INTEGRATION PROJECT: FY 13 ANNUAL REPORT

National Renewable Energy Laboratory (NREL), Southern California Edison (SCE) (2014)

Key Findings

The study evaluated the use of the EDD Distribution Engineering Workstation (DEW), a quasi-static time series power flow analysis platform, to develop a prescriptive methodology to test proposed generation performance criteria at the feeder level. Following the development of highly prescriptive methods for performing high penetration PV studies, example feeders were studied and mitigation techniques were evaluated for identified issues of exceeded performance criteria. The following are successful mitigation strategies modeled in case examples:

- SCE Fontana area circuitry experienced voltage rise issues that showed through modeling to be reduced by setting PV inverters to a fixed power factor (PF) of 0.95 absorbing.
- SCE Porterville circuit showed through modeling that a reduction in flicker (caused by PV variability) could be achieved by setting PV to a fixed PF setting of 0.975 absorbing.
- SCE Palmdale circuit showed through modeling that a reduction in flicker (caused by PV variability) could be achieved by setting PV to a fixed PF setting of 0.975 absorbing.

STOCHASTIC ANALYSIS TO DETERMINE FEEDER HOSTING CAPACITY FOR DISTRIBUTED SOLAR PV

Electric Power Research Institute (EPRI) (2012)

Key Findings

Analysis was conducted by EPRI to determine distributed PV impact to a specific feeder using a stochastic approach to develop potential PV scenarios. The analysis accounts for unknown project size and location of possible PV systems by examining thousands of potential scenarios and evaluating voltage, overload, protection, power quality and control impacts. In this study, OpenDSS is used to simulate thousands of potential PV deployment scenarios, and this analysis demonstrates that reviewing the results of these analyses in combination can then set percent penetration limits.

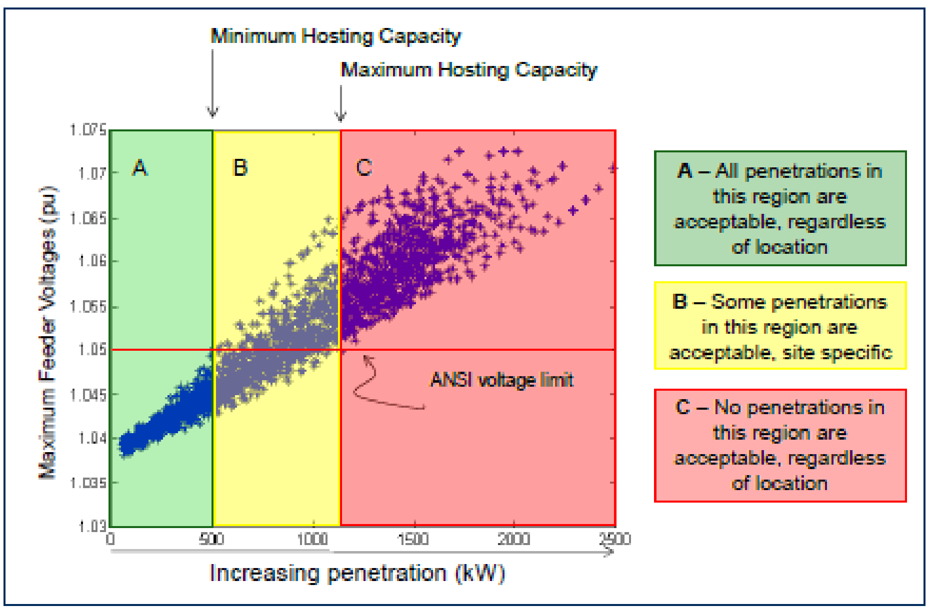

Figure 2-2 EPRI Diagram of Maximum and Minimum Hosting Capacity Analysis

TECHNICAL POTENTIAL FOR LOCAL DISTRIBUTED PHOTOVOLTAICS IN CALIFORNIA

Energy and Environmental Economics (E3), California Public Utilities Commission (CPUC) (2012)

Key Findings

This study aimed to estimate the technical potential for "local" distributed PV in the California investor-owned utility (IOU) service territories. Local PV was considered to be co-located with load (i.e., in urban areas), and it was assumed that technical potential was limited so that generation could not cause reverse power flow at the substation. Technical potential for local distributed PV was assessed for 1,800 substations and was determined to be approximately 15,000 MW between 2012 and 2020 for the study area. The following key findings were also identified:

- "Local" PV generally means a high reliance on rooftop systems.
- Rooftop projects are substantially more expensive than ground mount systems.
- To achieve significant local PV, projects should likely be evenly distributed throughout the system in rough proportion to load.
- Technical potential identified in this study is significantly higher than could be installed if potential were limited by the current Rule 21 interconnection tariff requirements.
- Expiration of the 30 percent federal investment tax credit in 2017 significantly increases the effective cost of local distributed PV.

VERIFICATION OF ENERGYNET METHODOLOGY

California Energy Commission, December 2010

Key Findings

The Energynet methodology, using GRIDfast optimization software, includes a solution with the capability to simulate the full power system including all distribution and transmission equipment in a single model and provide direct observation of grid impacts of individual distribution connected generation, including most potential types of impacts described above in Section 1. Building on this capability, the GRIDfast optimization software is also designed to complete the cost/benefit analysis for overall system optimization. (This software has since been commercialized by a firm called GRIDiant, which was acquired by Landis+Gyr in 2014.)

Producing sufficient data quality for distribution system components (every element of the dataset must be connected to every other element and every line element must be completely characterized) is a requirement to support the high-resolution power system simulation model and a challenge to widespread adoption. To address this problem, various source data was used with software infill. Only 60 percent of source data were used without infill, modification, or interpretation. Initial power flow solutions were used as screens for data errors.

A portion of the SCE distribution system has field measurement devices that gather actual data on system conditions Researchers were able to compare simulation results with system condition data taken from the field measurement devices to validate the modeling capabilities and accuracy. Statistical analysis described in the paper indicates simulation is a statistically significant predictor of actual field voltage data at an error level of less than 0.01 percent.

3. Key Information for PWP

The following section provides a summary of analytical approaches, key findings, and cost estimates from each study, as well as suggestions for future studies that PWP may consider.

SUMMARY OF ANALYTICAL APPROACHES

Table 3-1 compares the methodologies of the studies discussed in Section 2 in terms of simulation software used, modeling technique(s), performance criteria, and mitigation solutions considered.

Table 3-1 Summary of Analytical Approaches

STUDY	SIMULATION SOFTWARE	MODELING TECHNIQUE (1)	PERFORMANCE CRITERIA (2)	MITIGATION SOLUTIONS
Distributed Generation Interconnection Plan, HECO, 2014.	SynerGEE, PSS/E	All Circuits Queue for PV Dist. System & Feeder Steady State /Dynamic	Reverse Flow >50% at Sub > 33% GDML	Voltage Control Conductor Upsize Sub Xfmr Upsize Grounding Xfmr Distr. Xfmr Upsize
Duke PV Integration Study, PNNL, Duke, Alstom, 2013.	Alstom DMS	All Circuits & Example Evenly Distributed System & Feeder Steady State	System Losses Voltage Issue Overloads	Voltage Control Inverter PF Control
Impact of LER on SCE Transmission and Distribution System, SCE, 2012.	CymeDist	Example Feeder Rural/Urban Feeder Level Steady State	Voltage Issue Overload VR Operations	Distribution Upgrades from Existing Interconnection Studies
DG Integration Cost Study, Navigant, CEC, 2013.	Milsoft	Statistical Feeder Disperse/Clusters & Rural/Urban Feeder Level Steady State/Dynamic	Voltage Overloads VR Operation Reverse Flow Fault Duty Ratings Protection Voltage Flicker	Voltage Control Conductor upsize Cable upsize New Feeder/Sub Protection Change SCADA
High Penetration PV Integration Annual Report, NREL, SCE, 2014.	Distribution Engineering Workstation (DEW)	Example Feeder Not Directly Addressed Feeder Level Steady State/Dynamic	Voltage Overloads VR Operation Fault Current Protection	Inverter PF Control Advanced Inverter Communication
Stochastic Analysis of Feeder Hosting Capacity, EPRI, 2012	OpenDSS	Example Feeder Many Random Builds Feeder Level Steady State	Voltage Overload Protection Power Quality	Statistical Screening Method for Individual Feeders
Verification of Energynet Methodology, CEC, 2010.	GRIDiant/ GRIDfast	All Circuits User Defined System Level Steady State/Dynamic	Voltage Overloads Fault Duty Rating	Optimized Grid Planning Capacitor Banks System Upgrades

(1) How was feeder selected, how was PV distributed, system or feeder level simulation, steady state or dynamic.
(2) The types of impacts considered in the study; exceedance of performance criteria indicates issue.

In addition to the presentation of methodologies, each study attempted to identify key findings and these are summarized in Table 3-2.

Table 3-2 Summary of Key Findings

STUDY	KEY FINDINGS
Distributed Generation Interconnection Plan, HECO, 2014.	• Specific circuit and power system upgrades are required to enable higher levels of DG penetration in a proactive manner. • Advanced mitigation solutions are planned for future implementation. • TrOV threshold and thermal limit from reverse power flow were identified as the primary factors limiting a circuit's ability to integrate DG.
Duke PV Integration Study, PNNL, Duke, and Alstom, 2013.	• Multiple feeders can be assessed simultaneously through DMS software. • Net benefit of distributed PV is highly dependent on feeder topology, penetration level and interconnection point. • Greater voltage fluctuations were observed on feeders with PV. • Occasional reverse power flow and more frequent voltage regulation control actions were observed at high penetration levels.
Impact of LER on SCE Transmission and Distribution System, SCE, 2012.	• The location of PV installations (e.g., urban vs. rural) greatly influences the total impact to the distribution system. • Advanced mitigation solutions (e.g., advanced inverters and two-way communications) are planned for the future.
DG Integration Cost Study, Navigant and CEC, 2013.	• DG integration costs depend highly on location. • Integration cost is typically lower when DG is installed in urban areas. • Integration costs increase significantly as greater amounts of DG are clustered at the end of feeders. • Changes in automated control, system operating procedures, and policy may be required to encourage PV deployment in areas with the lowest integration costs.
High Penetration PV Integration Annual Report, NREL and SCE, 2014.	• Voltage rise and voltage flicker impacts can be successfully mitigated through inverter power factor settings. • Project work included development of visualization tools for measuring the extent and frequency of potential problems as well as comparing the effectiveness of various mitigation measures.
Stochastic Analysis of Feeder Hosting Capacity, EPRI, 2012	• Thousands of potential PV deployment scenarios can be simulated for a given feeder and performance results can be combined to determine penetration limits on a per feeder basis for all types of impacts. • Certainty about exact timing/location of PV deployment is not required.
Technical Potential for Local Distributed PV in California, E3 and CPUC, 2012	• To achieve significant local PV installation, projects should be evenly distributed throughout the system in rough proportion to load. • Rooftop projects are substantially more expensive than ground mount systems. • Technical potential identified in this study is significantly higher than could be installed if potential were limited by current Rule 21 interconnection tariff requirements.
Verification of Energynet	• High-resolution power system simulation tools can achieve very high accuracy and provide cost/benefit optimization.

Methodology, CEC, 2010.	• The simulation tools require very detailed data sets to define all electrical connectivity. This may be costly and time-consuming for utilities to assemble.

SUMMARY OF COST ESTIMATES

This survey examined a variety of integration studies that used many approaches to determining impacts of distributed PV and estimating integration costs. A comparison of reported average integration costs for each portfolio are included in Table 3-3.

Table 3-3 Summary of Reported Total Portfolio Per-Unit DG Integration Cost Estimates

STUDY, CASE	TOTAL PORTFOLIO INSTALLED DG (MW)	TOTAL PV PENETRATION (PERCENT)*	AVERAGE COST ($/KW)
HECO, DCIIP	602	60	323
Navigant, High Pen	6,000	25	267
Navigant, Base Case	4,800	20	224
SCE, Guided 50/50	4,800	20	256

Some studies (HECO and Navigant) examined multiple penetration scenarios, so it was possible to calculate the incremental per-unit integration costs. These are summarized in Table 3-3.

Table 3-4 Summary of Reported Incremental Per-Unit DG Integration Cost Estimates

STUDY, CASE	INCREMENTAL INSTALLED DG (MW)	PV PENETRATION RANGE (PERCENT)*	INCREMENTAL COST ($/KW)
HECO, 2014 – 2016	247	20 – 35	171
HECO, 2016 – 2020	130	35 – 45	110
HECO, 2020 – 2030	225	45 – 60	614
Navigant, Base Case v. High Pen, 2020	1,200	20 – 25	438

*PV penetration values in the tables above are on a capacity basis, and they are equal to the nameplate PV capacity divided by the expected system peak load. Penetration values on an energy basis are typically lower for PV than on a capacity basis, due to the expected annual capacity factor of solar PV production.

The integration costs noted above are the average integration costs for a large amount of installed DG. While average per-unit cost is a useful metric that can be applied when considering large DG portfolios, it is important to recognize that any particular DG installation may vary widely from the average cost based on a number of factors including installation location and feeder characteristics.

The level of distributed PV penetration is another major factor impacting the cost of integration. As demonstrated in Table 3-3 and Table 3-3, incremental per-unit integration costs tend to increase with rising PV penetration, because as penetration rises more costly mitigation solutions are required. The HECO study demonstrates this, since incremental costs for 45 to 60 percent penetration ($614/kW) are much higher than for 20 to 35 percent ($171/kW). The Navigant study is consistent with this finding as well; it reports much higher incremental costs for installations from 20 to 25 percent penetration ($438/kW) than for installations from zero to 20 percent penetration ($224/kW). The difference between the results of the HECO and Navigant studies highlights the fact that integration costs are likely to vary significantly between different utilities. This type of distribution-level integration study is still in its infancy in terms of methodology, so differences in results may stem from differences in methodology as much as fundamental differences between the utilities/feeders being studied.

Interestingly, in the HECO study, DG integration was less expensive on an average per unit basis for installations between 35 to 45 percent penetration ($110/kW) than for 20 to 35 percent penetration ($171/kW). This highlights the impact of major upgrades, which when triggered can greatly increase available hosting capacity until another major limiting threshold is reached.

FUTURE RESEARCH

During the course of this research, Black & Veatch found that there is universal agreement that each utility's distribution system is unique—and each distribution circuit is also unique—in terms of its hosting capacity and the integration costs it will incur related to distributed PV. Thus, while the information gathered in this report is useful for general guidance, PWP will ultimately need to perform modeling of its own distribution system in order to determine Pasadena-specific hosting capacity, mitigation solutions, and integration costs.

Black & Veatch is currently performing a study for Los Angeles Department of Water & Power (LADWP) which addresses these questions, and a study could be performed for PWP following a similar process:

- Select a small number of representative distribution circuits for detailed modeling.
- Build detailed circuit models in an appropriate software tool (e.g., CYME, Milsoft, SynerGEE, etc.).
- Perform an iterative modeling process on each circuit in which PV penetration levels are gradually increased until a violation occurs, cost-effective mitigation solutions are applied to resolve the violation, penetration is increased further until the next violation occurs, and so on until PV penetration reaches a threshold where it is no longer feasible to increase, i.e. the hosting capacity.
- Provide a summary of integration costs vs. penetration level by circuit.
- Extrapolate to estimate costs and hosting capacity levels for the entire distribution system.

Black & Veatch is ready to support PWP with any further studies it requires in order to ensure it can allow the growth of distributed PV while maintaining high distribution system reliability.

CONCLUSIONS

Based on the research conducted for this report, Black & Veatch highlights the following conclusions:

- Penetration of distributed PV in California has grown rapidly during the last 15 years, and is likely to increase significantly over the next several years.
- Distributed PV can have numerous types of impacts on distribution feeders, but many conventional and advanced solutions are available to mitigate these impacts.
- Each utility's distribution system, and each distribution feeder, is unique in its capacity to accommodate distributed PV.
- Detailed modeling is required to determine the hosting capacity of each feeder, and analytical approaches and software tools are emerging to facilitate such studies.
- Until now, the interconnection process appears to have prevented PV installations from causing significant impacts on PWP's distribution system, but as penetration increases in the future it is likely that integration costs will become substantial and will rise with penetration.
- Results from studies in Hawaii and California indicate that interconnection facilities and distribution upgrades are likely to have an average cost of $200-300 per kW of PV installed, but can range up to $400-600 per kW at higher penetration levels.