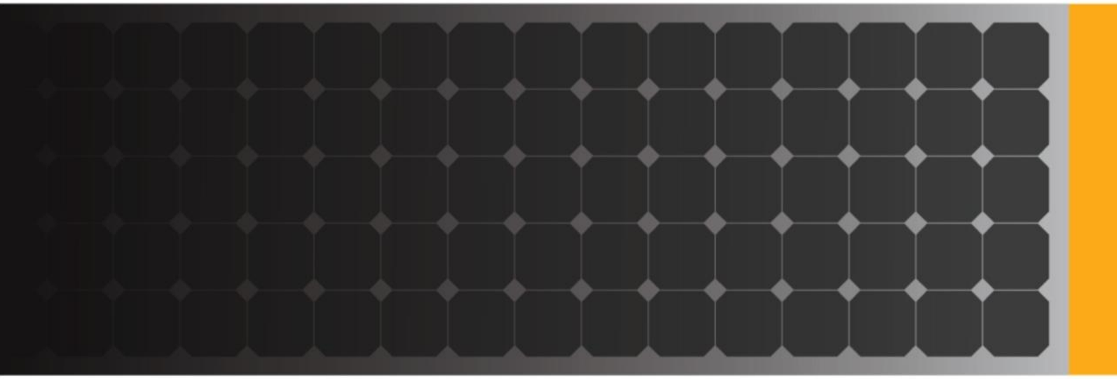
PJM Interconnection- Net Metering Task Force



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Solar Developer Perspectives

Jim Torpey
March 19,2012

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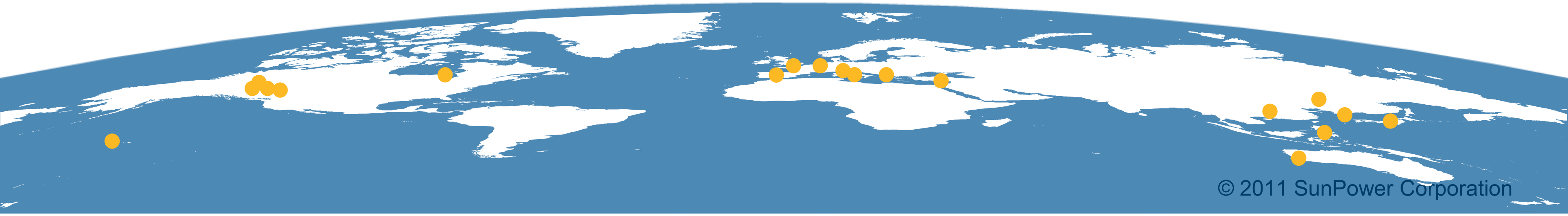
SunPower 2012

- World-leading solar conversion efficiency
- >2 GW solar PV deployed by year-end
- Diversified portfolio: roofs to power plants
- More than 180 patents, 5,000+ employees
- HQ- California w East Regional HQ in Trenton NJ
- >875 MW guided 2011 cell production



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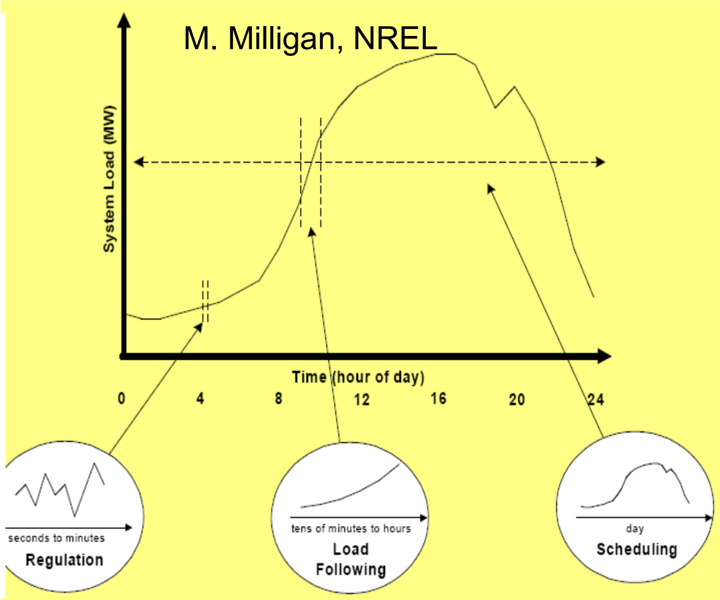
INTERCONNECTION AND GRID INTEGRATION

Major Distributed PV Integration Concerns

Issue	Distribution System Concerns
Sub-hourly Variability	Voltage control, equipment cycling, flicker.
Distributed Generation	Voltage rise / profile, reverse power flow.
Fault Behavior	Short-circuit contribution, unintentional islanding, "sympathetic" tripping.
Monitoring, Real & Reactive Power Control	Situational awareness, system management

Dealing with Solar Variability


M. Milligan, NREL

Timeframe	System Impacts	Local grid Impacts
Short term Seconds to Minutes	Regulation	Voltage Fluctuation
Mid term 10's of Minutes to Hours	Load Following	Voltage Profile
Longer term Hours to Days	Scheduling	

Implication Of Diversity Over Short Distances

- With many smaller systems spread out across a distribution circuit, short duration variability is unlikely to cause issues even at high penetration because no one system can significantly impact voltage, and variability is uncorrelated.

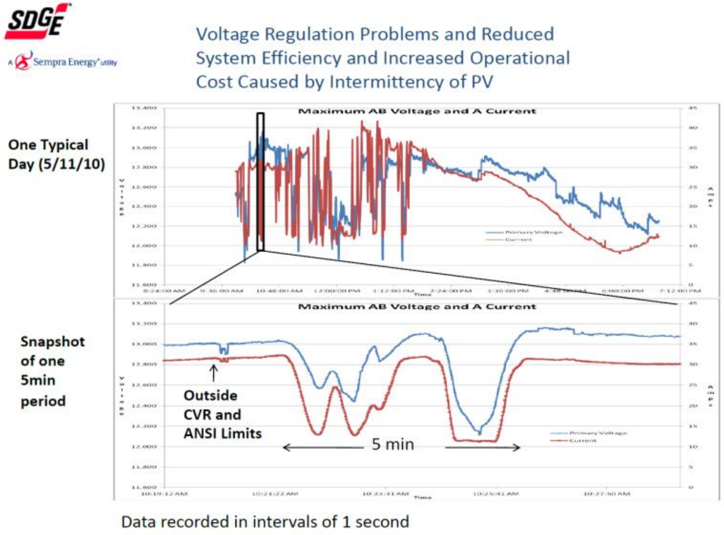
- For single, relatively large (high penetration) systems, particularly in a high impedance location on the circuit, output variability can be an issue on the timeframe of minutes.

    - Voltage can experience large fluctuations.

    - This can trigger undesirable control behaviors (frequent LTC, cap bank switching).

- However for larger single systems, diversity within the plant appears to smooth very short duration fluctuations (over a few seconds) which are seen in irradiance data – no evidence of flicker issues due to variable cloud conditions.

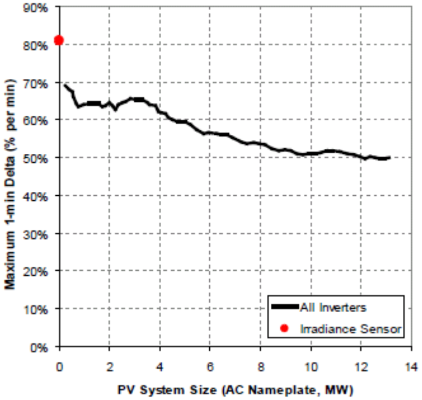
- Significant reductions in variability at <= 1-minute timeframe are seen within PV systems of 10+ MW.



Voltage Regulation Problems and Reduced System Efficiency and Increased Operational Cost Caused by Intermittency of PV

Data recorded in intervals of 1 second

Plots from recent SDG&E testimony on high penetration DGPV deployment highlight utility concerns about voltage control*.



Example of observed reduction in variability within a 10 MW-class PV system on a 1-min basis.

*1 MW system, single day, no context given on feeder configuration, penetration relative to load, or frequency of occurrence.

High Penetration Circuits Around The World

Numerous studies indicate that integration of high penetration of PV onto distribution circuits is feasible without major system upgrades.

Location	Description	Penetration	Notes
Ota City, Japan (2003)	550 Sites / 2 MW residential, one circuit	Not Reported	Residential energy storage evaluated and removed; no issues reported post-removal.
Freiburg, Germany (2006)	70 Sites / 440 kW multi-unit residential	110% on capacity (400 kVA XFR)	Minimal, correctable issues reported (phase imbalance)
Kona, HI (2009)	700 kWac commercial	35% on capacity (2 MVA feeder), backfeed up to 30% in low load	No issues reported
Lanai, HI (2009)	600 kWac commercial (1.2 MW system, brought online incrementally)	~12% on capacity, ~25% in low load, weak island system	No issues reported.
Anatolia, CA (2009)	115 Sites / 238 kW residential	4% on capacity, 13% low load	No issues reported, PV variability less than AC cycling variability.
Las Vegas, NV (2008)	> 10 MW commercial, 35 kV interconnection	~ 50% on capacity, ~100% low load	No issues reported
Atlantic City, NJ (2009)	1.9 MW commercial, 23 kV interconnection	~24% on capacity, ~63% low load	No issues reported

Anti-Islanding & Fault Ride Through

- Concern that DG may cause an unintentional island within the distribution system motivates anti-islanding requirements

- PV system anti-islanding proven to be very effective at getting systems offline quickly in the case of a distribution circuit fault

- In high penetration scenarios, you <u>do not</u> want to clear DG suddenly if there is a system-wide fault. Examples: Voltage depression due to transmission system instability, “50.2 Hz problem”.

- PV systems can be programmed to behave as desired, including low-voltage ride through & frequency responsive droop. Capabilities have been implemented commercially in Germany, at utility scale plants, and in island micro-grids.

- US regulatory standards do not comprehend high penetration DG; updates to allow / require desired behavior are in process

- **Related issue – 15% SGIP “study screen” a barrier in many cases, originally based on concern about anti-islanding failing at higher penetration - not borne out in practice**

- Up to15% often viewed as a conservative “no further study needed” penetration - purely anecdotal. However some continue to erroneously assert 15% is an “upper limit”

Summary of Global Experience W Solar Grid Integration

- Voltage rise & impact on voltage profile, reverse power flow
  - In general has not been a problem, but can limit installs in some cases (i.e. long rural feeders)
  - Distribution system in Germany more modern than much of US (bidirectional relaying is the norm)
  - **System upgrades in the US will definitely facilitate more PV – but needed regardless of PV**
- Visibility and Control
  - Monitoring and real / reactive power control of large systems (10 MW+) generally provided (SCADA)
  - Lack of visibility, control of smaller DG generation is a significant concern
  - German TSOs use regional level estimates and forecasts of PV generation (4-5% RMSE)
  - German TSOs also will have basic curtailment control via low-cost infrastructure (ripple control)
  - Spain now requires telemetry from larger systems to TSO; also forecasts PV
  - Neither German or Spanish DSOs have real-time visibility
  - US approach is a work in progress:
    - Perception of a need for data from all PV systems into dist. ops. from some US utilities
    - Utility SCADA comms to mid-size systems (100's of kW) extremely expensive, not scalable
    - "Gating" high penetration PV by rollout of SG comms will likely be a barrier
    - **Discussion in US must mature – what data is needed, what resolution (time / space), when (ops vs. planning)**

Summary (continued)

- Unintentional islanding, Short circuit contribution

    - Unintentional islanding often a significant worry for utilities in US, but not in Europe
        - European studies and experience indicate that risk is extremely low.
        - US perceptions are often not well informed.

    - Short circuit contribution has not been a problem to date but often a discussion point in technical circles.

- “Sympathetic” tripping of DG

    - Need for DG to trip on local fault but ride through transmission fault.
    - Unlikely to be an issue until high penetration (one study showed an issue at ~20% of system energy)
    - Germany preparing for high pen by requirement of voltage and frequency ride-through for DG.
    - Expect similar Europe-wide requirements from ENTSO-E.
    - NERC (IVGTF) and IEEE 1547.8 committee addressing this by developing standard.

- Fault Behavior of Large Plants

    - Requirements for large PV plants follow from current wind and conventional plant requirements.
    - EU was burned by lack of wind requirements, leading to difficult recovery from 2006 UCTE breakup.
    - No technical barrier to meeting requirements (e.g. voltage / frequency ride through)
    - One issue (particularly in US) is lack of standards or test protocols for non-DG PV inverters / plants.

Conclusions

- Local impacts of PV variability on the distribution system do not appear to be a significant issue in general, and can be managed with advanced controls if needed.

- Penetration of VERs up to ~20-30% of energy has been shown to be manageable, with current technology and generation mix, in multiple recent in-depth studies.

- Accurate forecasts; flexibility (flexible generation, energy storage, demand response); operation strategies; transmission; and changes to markets & policies will all reduce integration costs now and may be necessary to achieve VER penetrations beyond ~ 30% without excessive curtailment.

- The combination of storage and PV to provide added value to the customer appears promising. Technical and economic validation is in progress.

Conclusions

- Significant amounts of high penetration (>100% of minimum load), distributed PV generation have been successfully integrated worldwide.

- Geographical diversity substantially mitigates short duration variability, even within the footprint of a given feeder.

- Many often discussed concerns such as voltage fluctuation, failure of anti-islanding, and unacceptable harmonic contribution have not emerged in practice.

- Experience in Germany and Spain suggests that mid-term goals (e.g. 33% RPS in CA by 2020), even with PV predominately deployed as DG, is readily achievable with no significant technical barriers.

- Functionality similar to that required by German MV directive, applied to all PV systems, is expected to be adequate to meet much higher penetration levels in Germany moving forward.

- European studies indicate that reactive power control of DGPV significantly increases the ability of a circuit to accommodate PV without requiring other upgrades.

- Distribution system upgrades to <u>current</u> state of the art will substantially increase allowable penetration levels, benefit many stakeholders including utilities and all their customers.

CURRENT BEST PRACTICES- INTERCONNECTION

Hawaii Rule 14H
California Rule 21 (pending)

Updating Interconnection Screens for PV System Integration

Michael Coddington, Benjamin Kroposki, Barry Mather – NREL
Kevin Lynn, Alvin Razon – DOE
Abraham Ellis, Roger Hill – Sandia National Labs
Tom Key, Kristen Nicole, Jeff Smith – EPRI
Technical Report
NREL/TP-5500-54063
January 2012

VALUING EXPORTED ENERGY FROM DISTRIBUTED SOLAR GENERATORS

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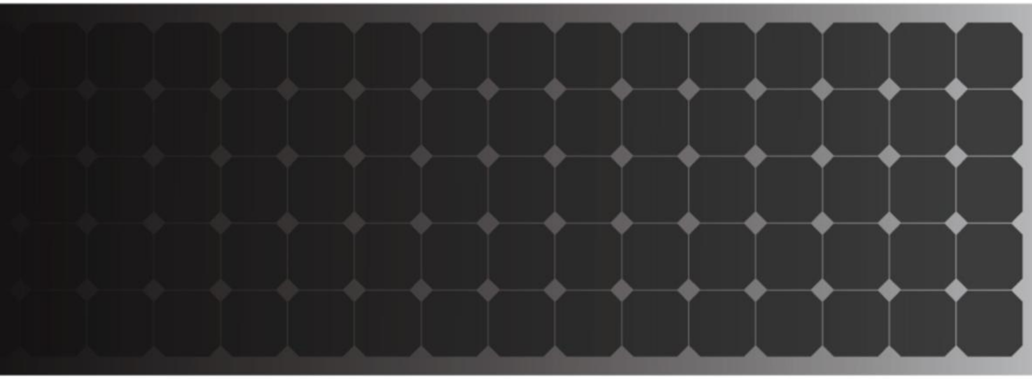

NET METERING AND BEYOND

NET METERING

- Net metering serves as a proxy for delivered value to the grid- both peak energy and distribution value
- Comprehensive studies in Austin, California, Wisconsin and New York indicate a value range of $.09- $.40/kwh for exported solar generation.
- Uncovering value in specific grid locations requires more transparency and utility cooperation
- Properly valuing exported solar generation requires change in PJM procedures so that customer load profiles from solar customers are recognized and suppliers can benefit from serving solar DG customers
- Some current net metering issues revolve around billing, accounting and interpreting rules for different customer rate classes

THANK YOU

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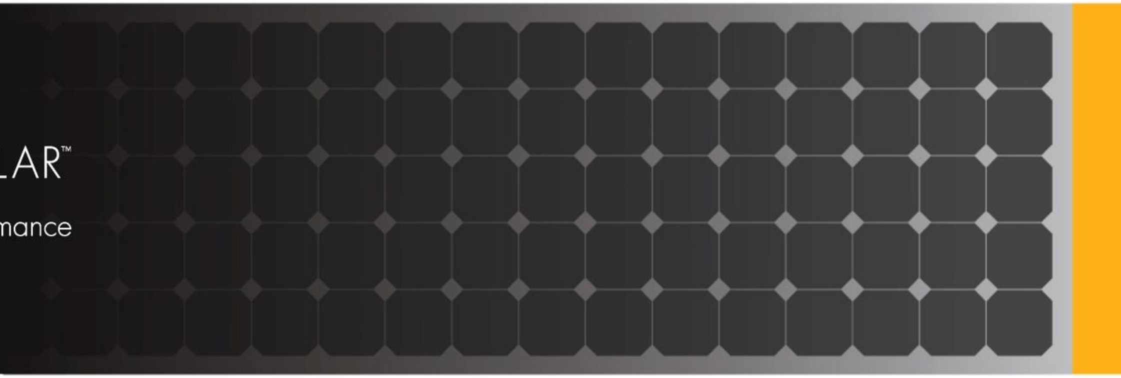
Highest Efficiency | Highest Reliability | Guaranteed Performance



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APPENDIX


THE WORLD'S STANDARD FOR SOLAR™
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Mitigation Of Local Voltage Impacts

- Geographical diversity has a substantial impact in mitigating variability over small distances, even within a distribution feeder.

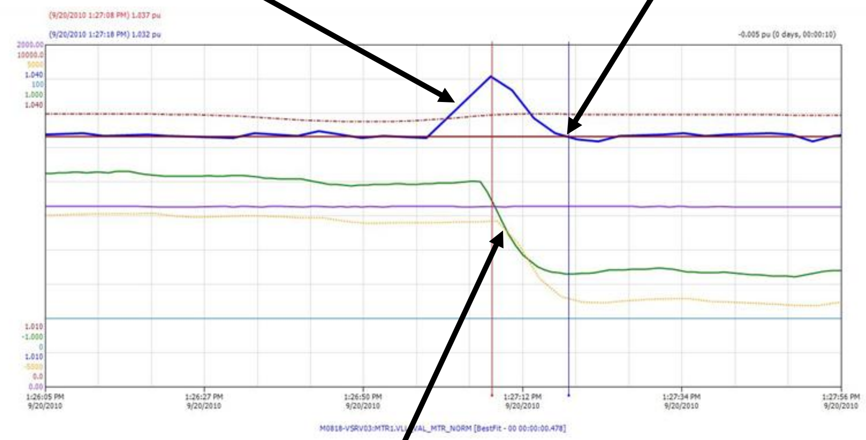
- Though uncommon, voltage fluctuations can result when a single, high penetration system is interconnected to a circuit with high impedance (such as a long rural feeder).

- Reactive power control can substantially reduce the impacts of output variability on voltage.

- Active voltage regulation (AVR) is particularly effective, if mitigation is needed.

(1) Spike in voltage at POI detected

(3) Voltage returns to setpoint



(2) SunPower smart controller commands reactive power change to reduce voltage

SunPower has pioneered the implementation of AVR in large-scale PV plants.

High Penetration Case Study – Lanai, HI

- Currently operating at 600 kW - up to 24% of island’s power in low load conditions.
- Tied to 12.47 kV feeder, routinely back feeds (>100% penetration).
- PF is remotely adjustable by MECO, typically operates at 0.98 leading (inductive)
- No discernable impact on voltage (or frequency) under highly variable conditions.

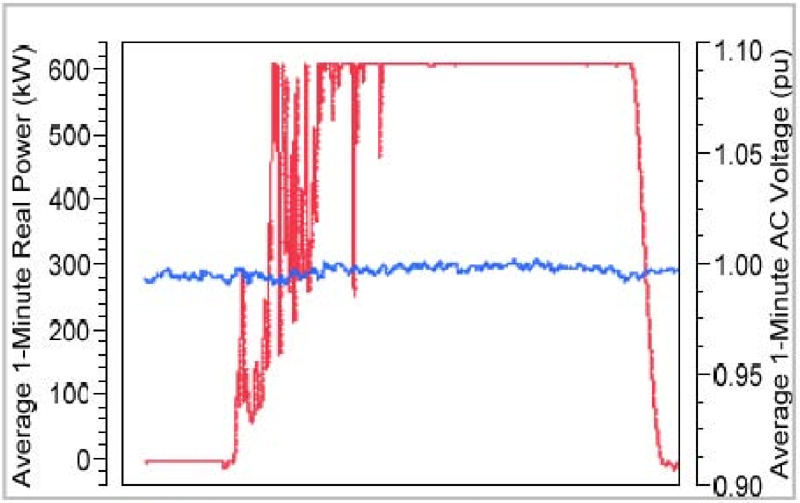
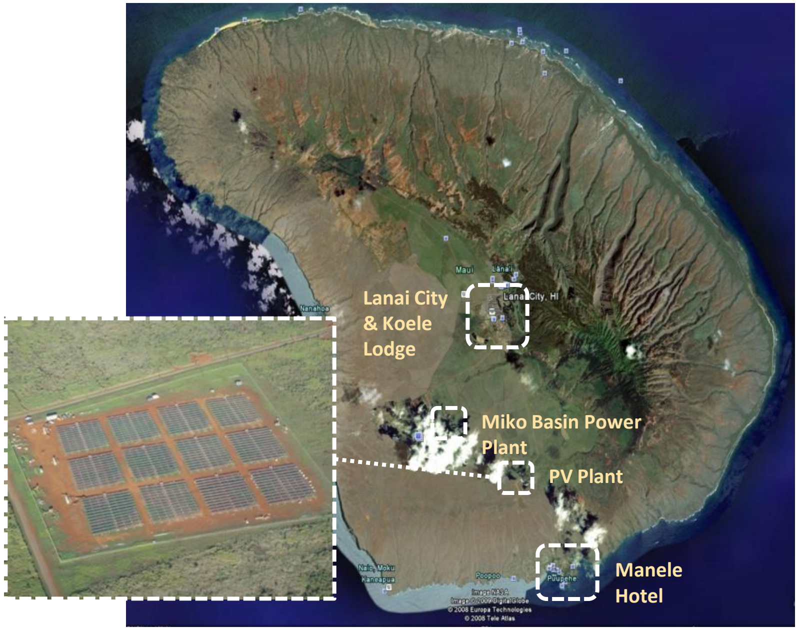


Figure 5. PV plant power output (red) and grid voltage (blue) on April 11, 2010

Johnson *et. al.* IEEE PVSC 2010



Does PV Variability Present A Barrier To Adoption?

Some have used the following argument:

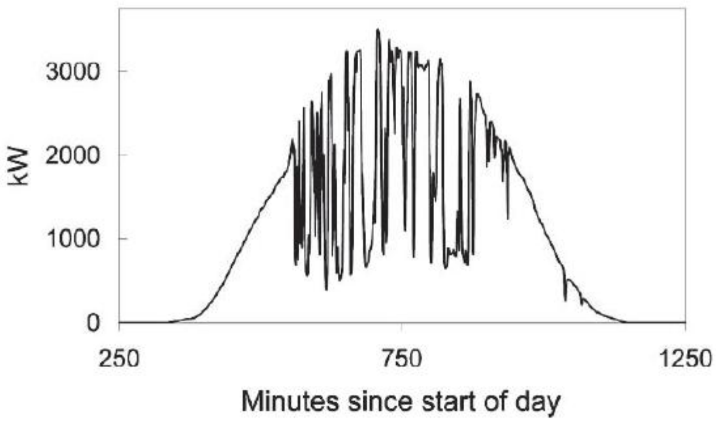


Figure 6-1
Output on June 3, 2004 for Tucson Electric Power's Springerville PV Plant. Data is Based on One Minute Increments

→ **BAD**

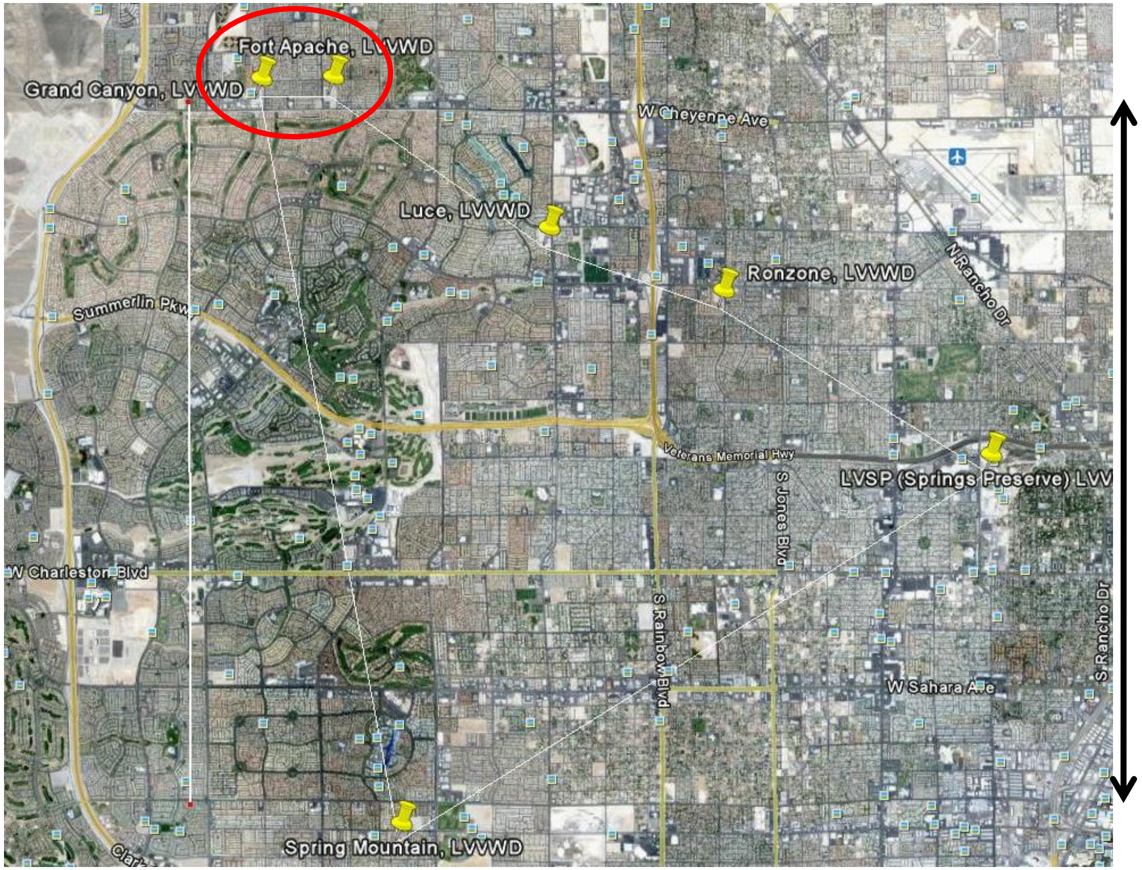
However, this *does* beg a few important questions, such as:

- How rapid are these changes, and how often do they occur?
- Does the observed behavior of a single system scale? If so, how?
- What are the impacts of variability on the utility infrastructure and the customer?
- How do these impacts change as penetration increases?
- What mitigations are available for these impacts? What are the best solutions?

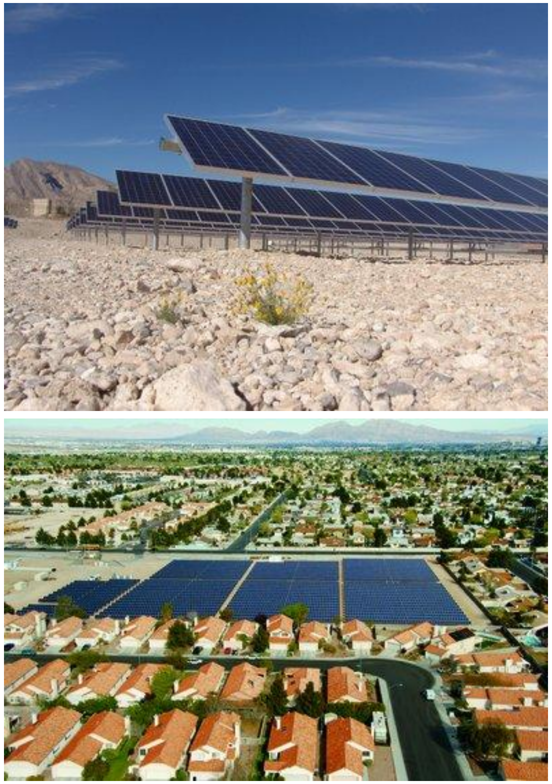
What About Over Short Distances?

Case Study: Los Vegas Valley Water District

Six Distributed Sites. Minimum Distance: Grand Canyon – Ft. Apache = 1 km

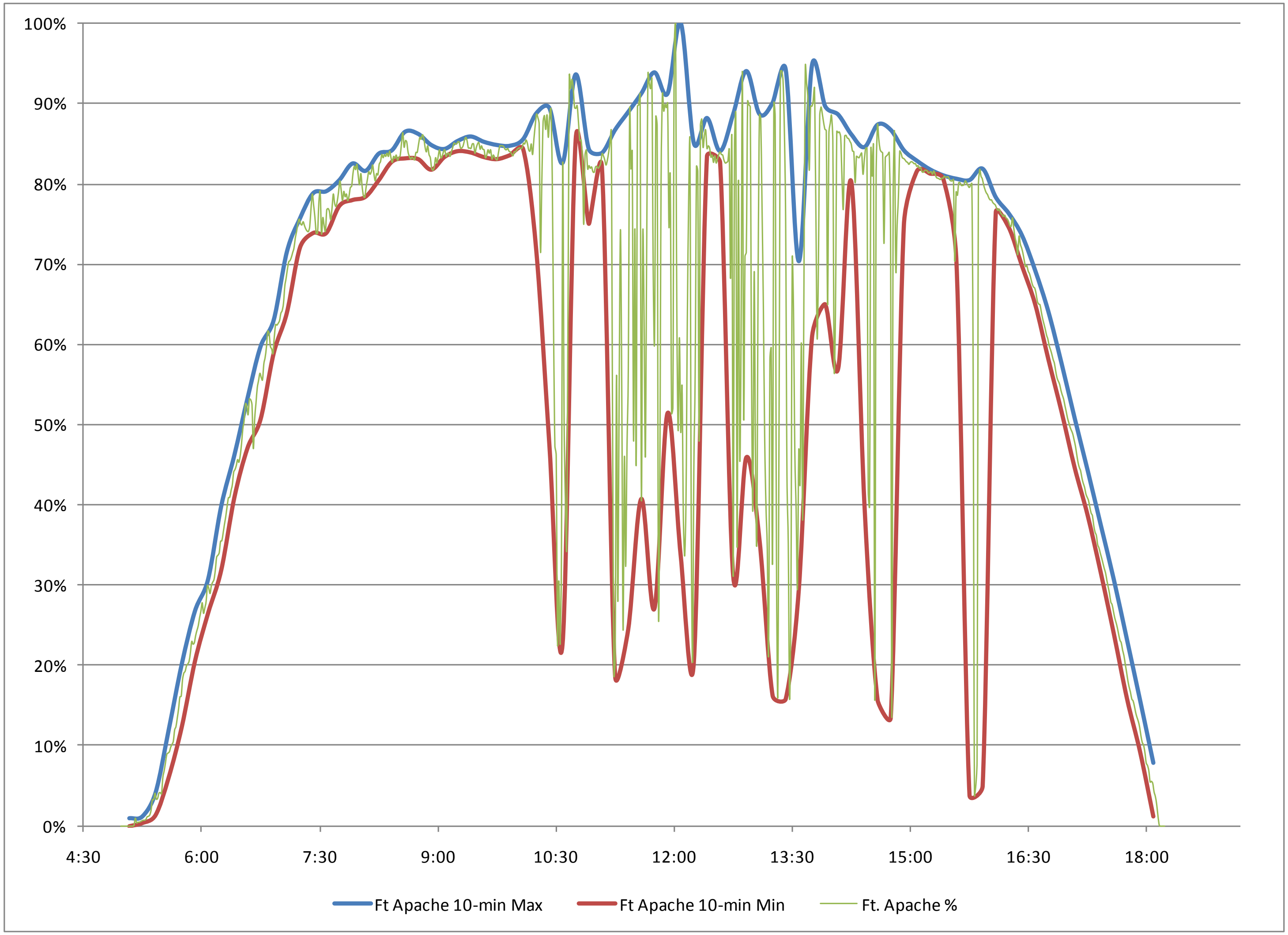


10 km



Top – Grand Canyon
Bottom - Ronzone

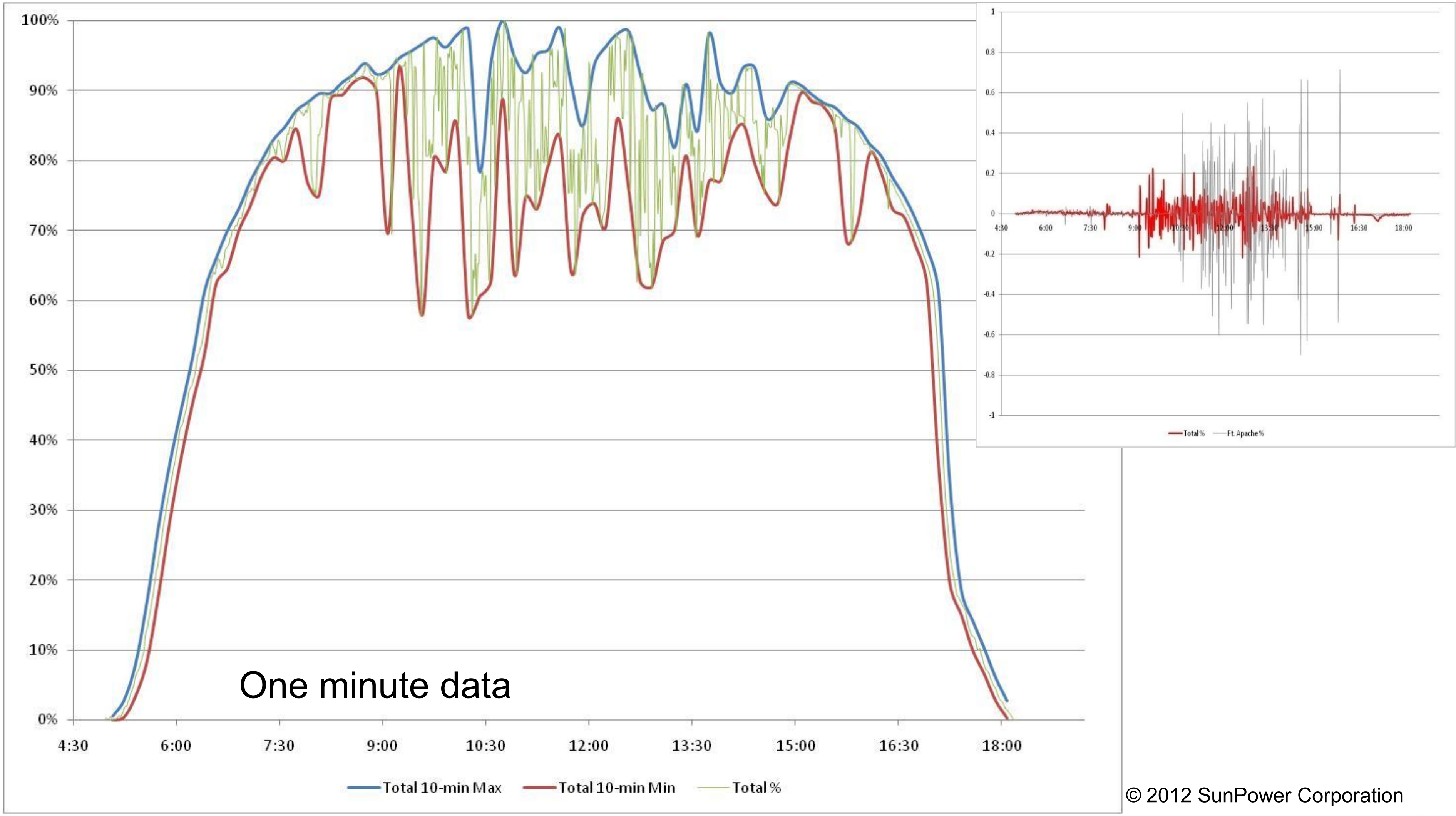
Single Site – Highly Variable Day



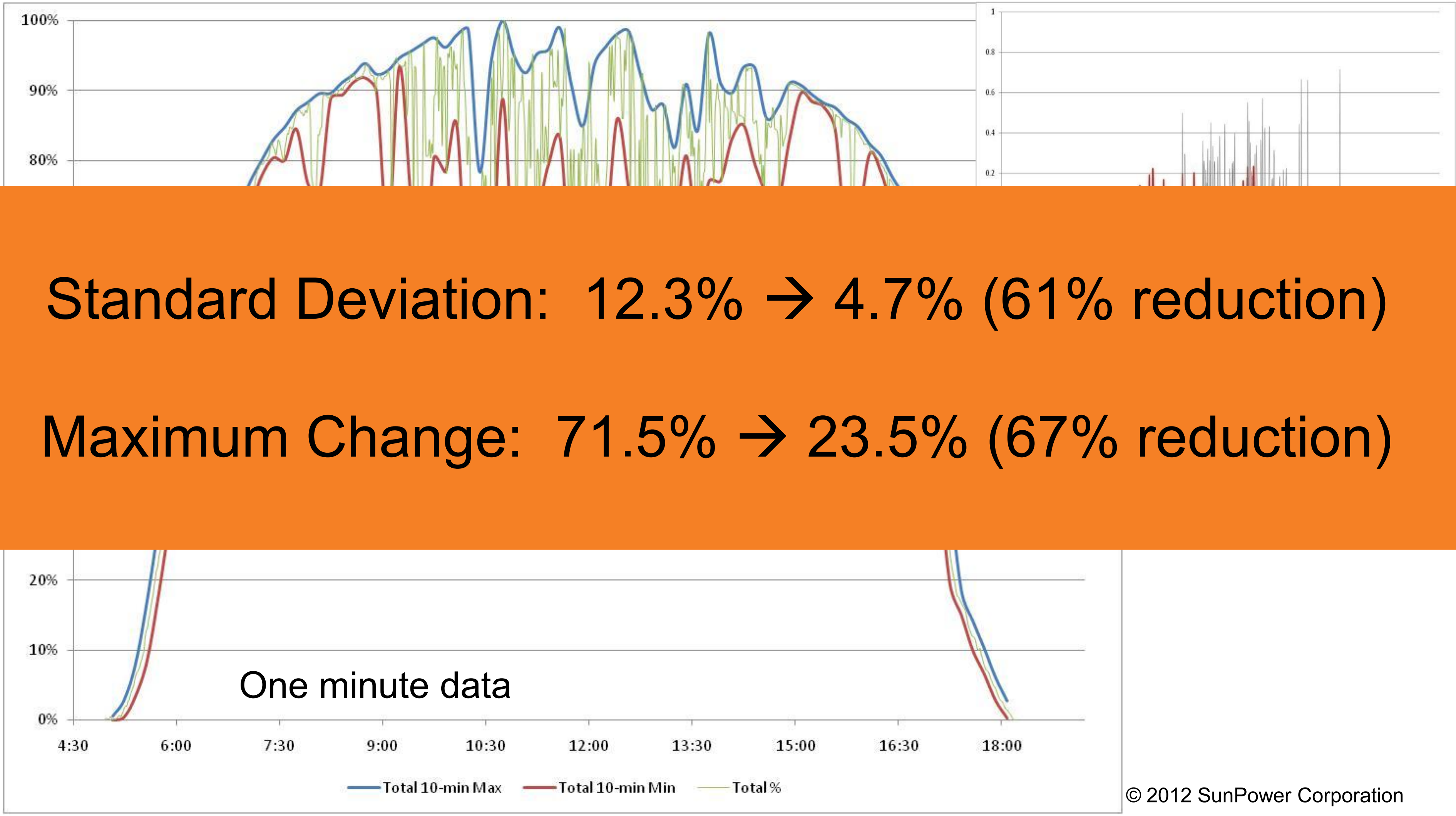
One minute data (Ft. Apache)

Partly cloudy day, highly variable conditions.

6 Sites, 1-10 km apart (same day)



6 Sites, 1-10 km apart (same day)



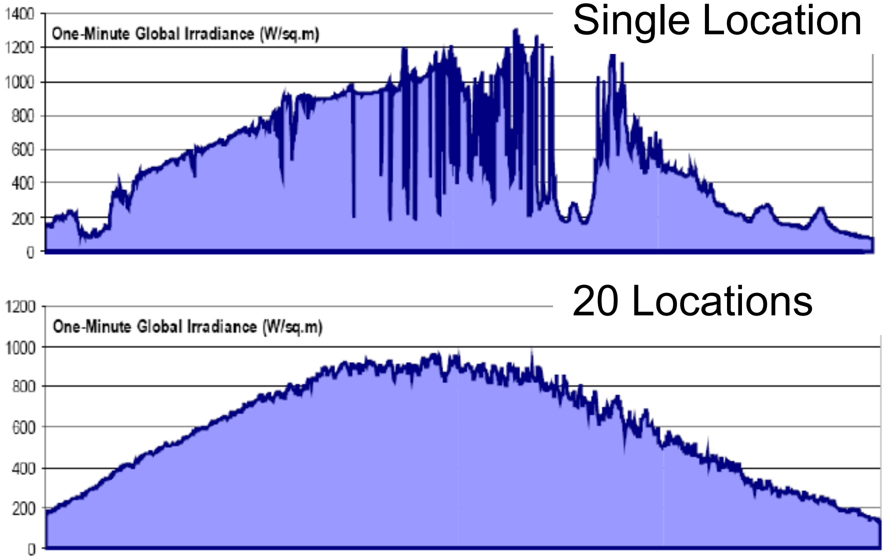
Standard Deviation: 12.3% → 4.7% (61% reduction)

Maximum Change: 71.5% → 23.5% (67% reduction)

One minute data

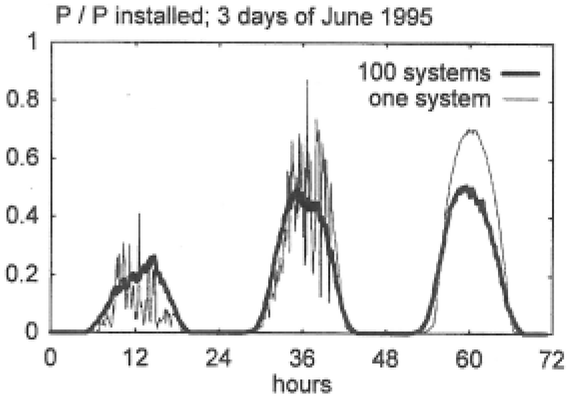
Geographical Diversity Is A Crucial Factor

High Irradiance Variability At Single Sites Is Reduced With A Portfolio Of Sites

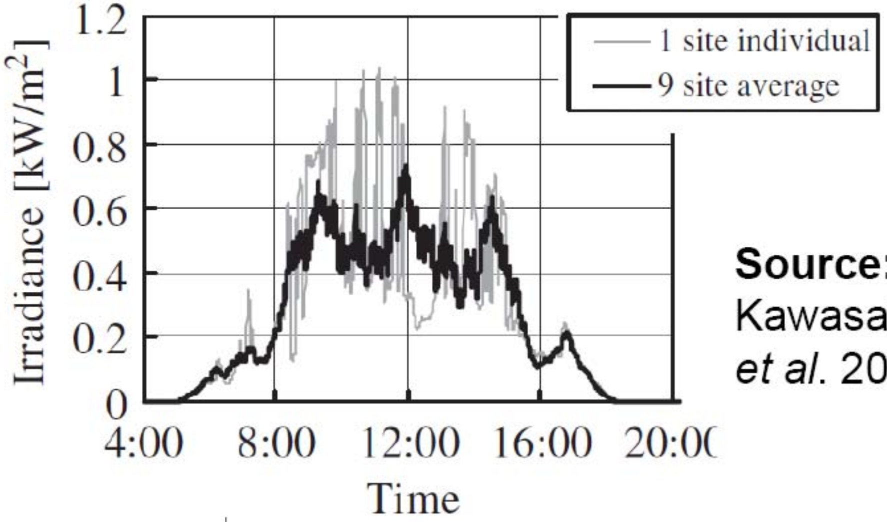

Single Location

20 Locations

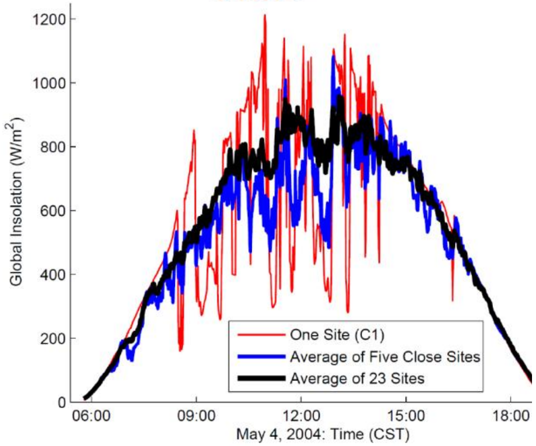
Source: Hoff et al. 2008



Source: Weimken *et. al.* 2001



Source: Kawasaki *et al*. 2006.



Source: Mills *et. al.* 2010

Diversity Is Very Powerful Over Large Areas

- Tom Hoff (Clean Power Research) recently analyzed variability of a 5400 MW fleet of PV plants (5 MW – 500 MW in size) across California.

- On a moderately variable day, for 1 location (equivalent to a ~5 MW or smaller system), the standard deviation of 1-minute variability was **~10%**.

- For all locations, the standard deviation of 1-minute variability was **~0.3%.**

- **That is, a 97% reduction in variability was found in this analysis**.

- **Controlling (or "firming") the output of individual plants would require at least 33 times** the installed regulation capacity than controlling the variability of the fleet in aggregate.

- Combining aggregate solar variability with other uncorrelated variability, from load and wind, would further reduce the total regulation required compared to that required to manage each taken individually.

System Level Impacts Of Short Duration Variability

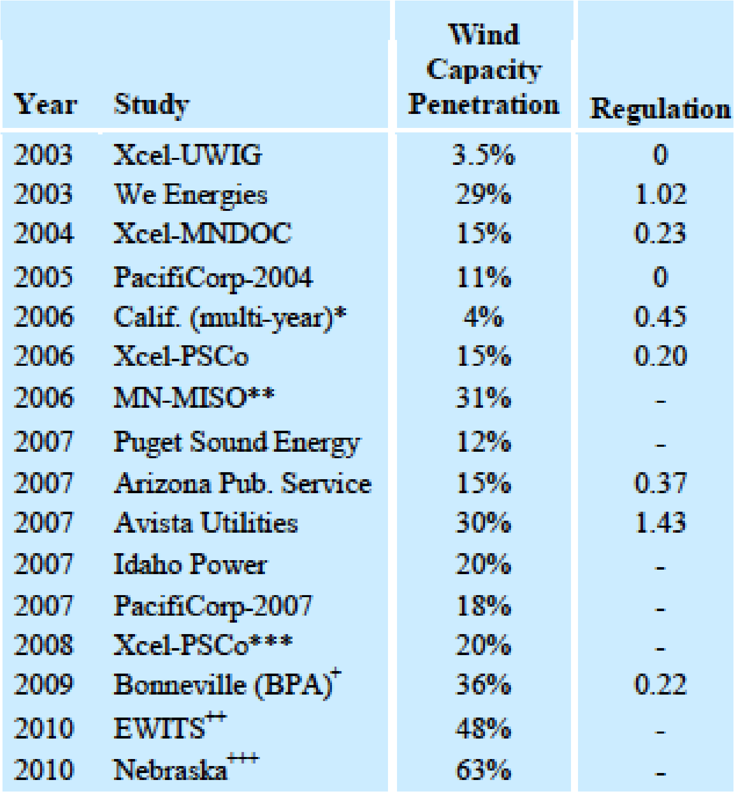
- System level impact is cost required to provide incremental frequency regulation due to added sub-10 minute variability from PV.

- PV integration cost per recent LBNL (Mills & Wiser) stud - comparable to wind, because

  - Geographical diversity substantially damps short duration fluctuations

  - Reserves can be scheduled based on deterministic “clear sky” envelope

- Regulation costs for wind (up to ~ 30% penetration) across multiple studies are generally very modest at <$1 / MWh.



Year	Study	Wind Capacity Penetration	Regulation
2003	Xcel-UWIG	3.5%	0
2003	We Energies	29%	1.02
2004	Xcel-MNDOC	15%	0.23
2005	PacifiCorp-2004	11%	0
2006	Calif. (multi-year)*	4%	0.45
2006	Xcel-PSCo	15%	0.20
2006	MN-MISO**	31%	-
2007	Puget Sound Energy	12%	-
2007	Arizona Pub. Service	15%	0.37
2007	Avista Utilities	30%	1.43
2007	Idaho Power	20%	-
2007	PacifiCorp-2007	18%	-
2008	Xcel-PSCo***	20%	-
2009	Bonneville (BPA)[+]	36%	0.22
2010	EWITS[++]	48%	-
2010	Nebraska[+++]	63%	-

Diurnal Variability – An Important Consideration

- Daily solar cycle can add load following and unit commitment integration costs; bigger ramps.

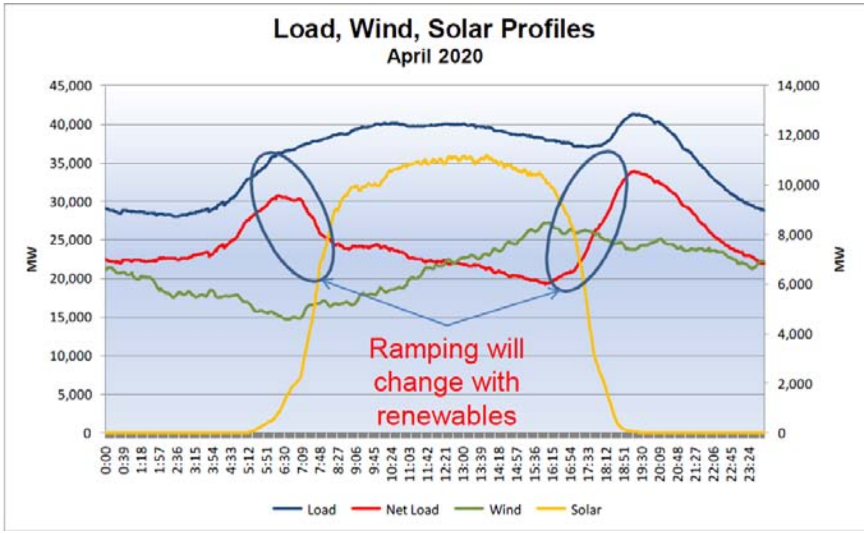
- LBNL, NREL (EWIS / WWIS) and others find modest total integration cost up to ~30% energy penetration: typically less than $5 / MWh (for wind and solar).

- Forecast error dominates cost, PV forecasting is new, often assumed to be very inaccurate in integration studies (5-20% error)

- May 2011 CAISO reported that 33% RPS is manageable using 2020 gen mix, with limited curtailment of VERs in a few hours to address high downward LF req't.

- CAISO requirements decreased dramatically from previous assessments given updated (reduced) forecast error assumptions.

- 4-5% RMSE is achieved in practice for regional-level PV forecasts in Germany, comparable to best in class wind forecasting.



CAISO Projection with 12.3 GW PV – a "bad" day

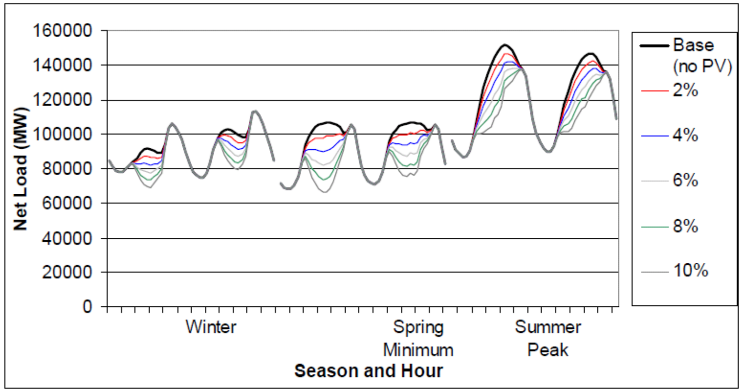


Figure 9. Load Shapes in WECC with Various PV Penetration Scenarios

Denholm *et al* 2008 (% system energy)

PV in Europe and California By The Numbers

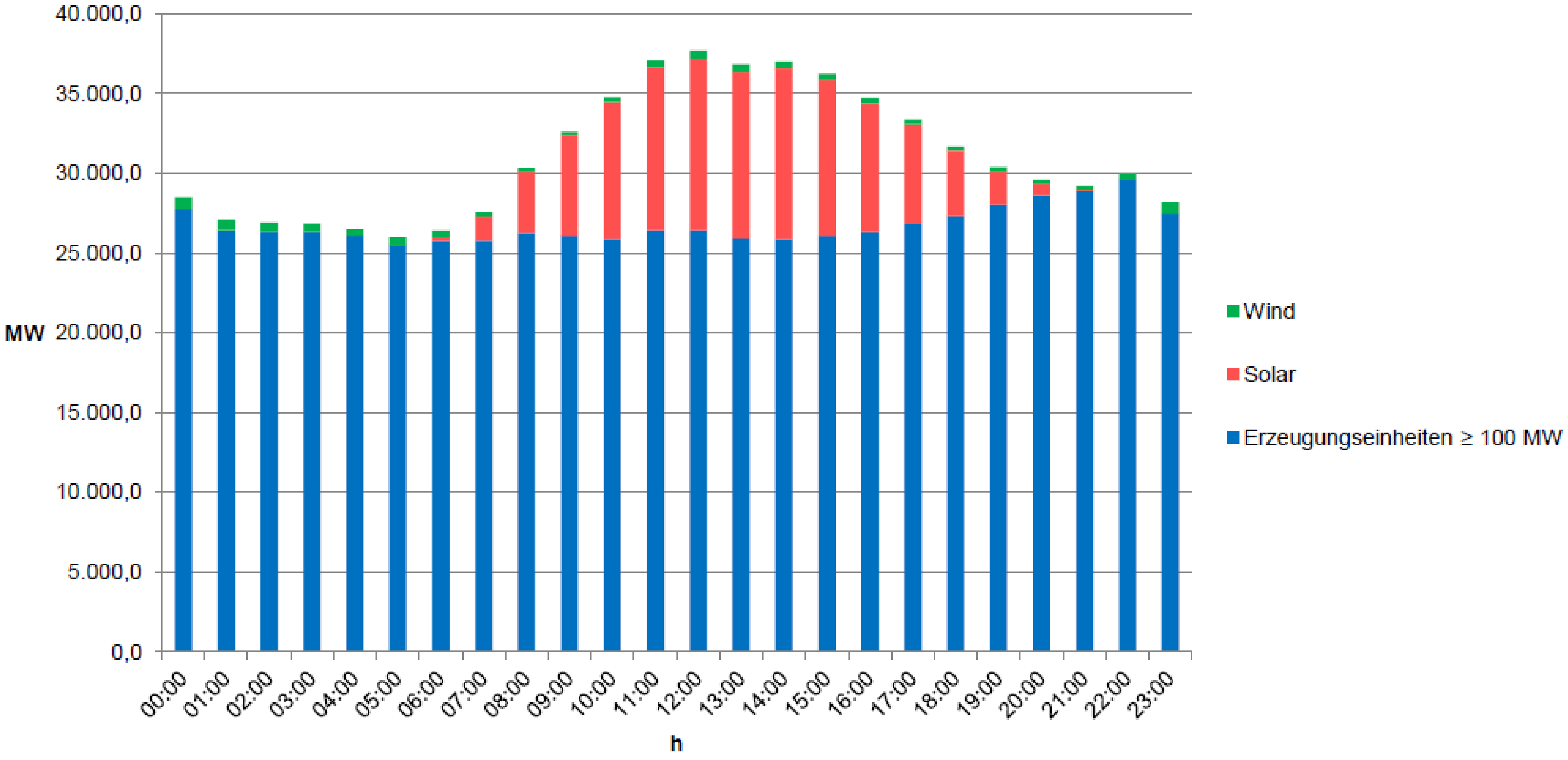
Region	Installed PV	Peak Summer Demand	% Penetration (Capacity)
Germany	~20 GW	78 GW	25%
Spain	3.5 GW	41 GW	8.5%
CA	1.0 GW	~59 GW	1.7%
CA 2020 33% RPS High DG	15.1 GW	~70 GW	21.5%

Take-Aways

- California is an order of magnitude away from Germany's current PV penetration.
- By 2020, CA would approach Germany's current penetration level in the 33% RPS High DG scenario.
- There are 70 GW of large scale PV projects in CAISO's queue – trigging concern at the ISO.
  - Much of this will not be developed.
  - Surviving pipeline is expected to achieve 33% RPS without requiring DGPV.

Data sources: Photon Consulting, "33% RPS Implementation Analysis – Preliminary Results" CPUC 2009, "California Energy Demand 2010-2020, Adopted Forecast" CEC 2009.
All peak demand is for 2010 except CA 2020 case.

High Penetration In Germany



6/12/2011

Distributed PV supplying 30.1% of load at noon

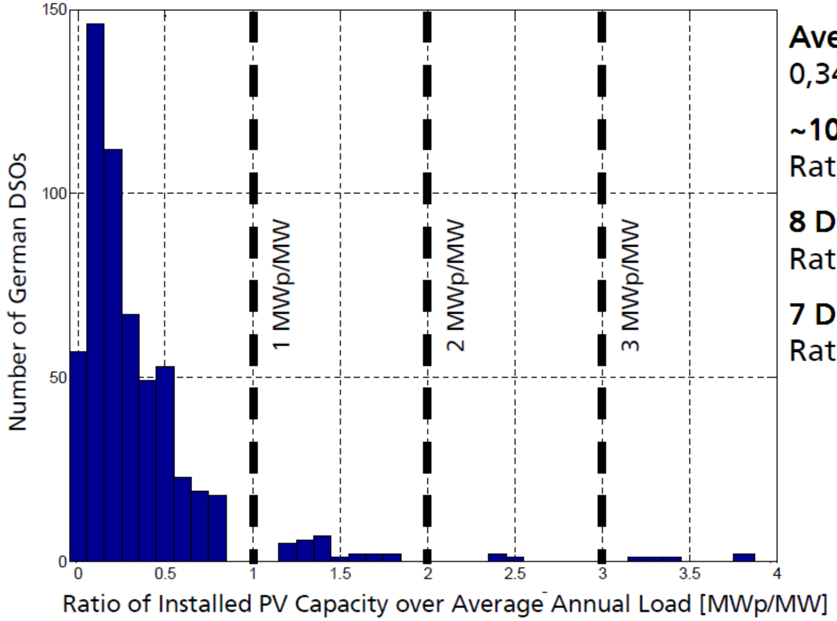
Data: European Energy Exchange (EEX) Transparency Platform

High Penetration In Germany

Germany Today:

- *Distributed:* 99% DG, 82% (15+ GW) < 1 MW in size
- *Concentrated:* ~70% in S. Germany
- Penetration exceeding 100% of feeder minimum load is fairly common

Ratio of Installed PV Capacity over Average Annual Load [MWp/MW]



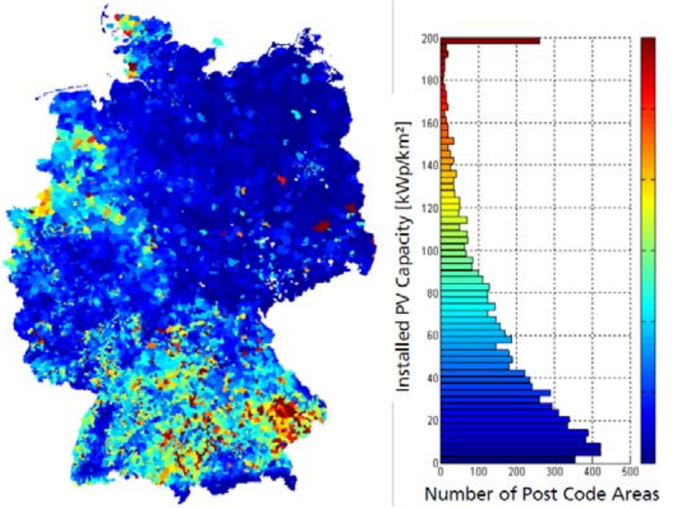
Average Ratio:
0,34 MWp/MW

~10% of the DSOs:
Ratio > 1 MWp/MW

8 DSOs:
Ratio 2-3 MWp/MW

7 DSOs:
Ratio 3-4 MWp/MW

Source: Y.-M. Saint-Drenan 2010 (IWES)



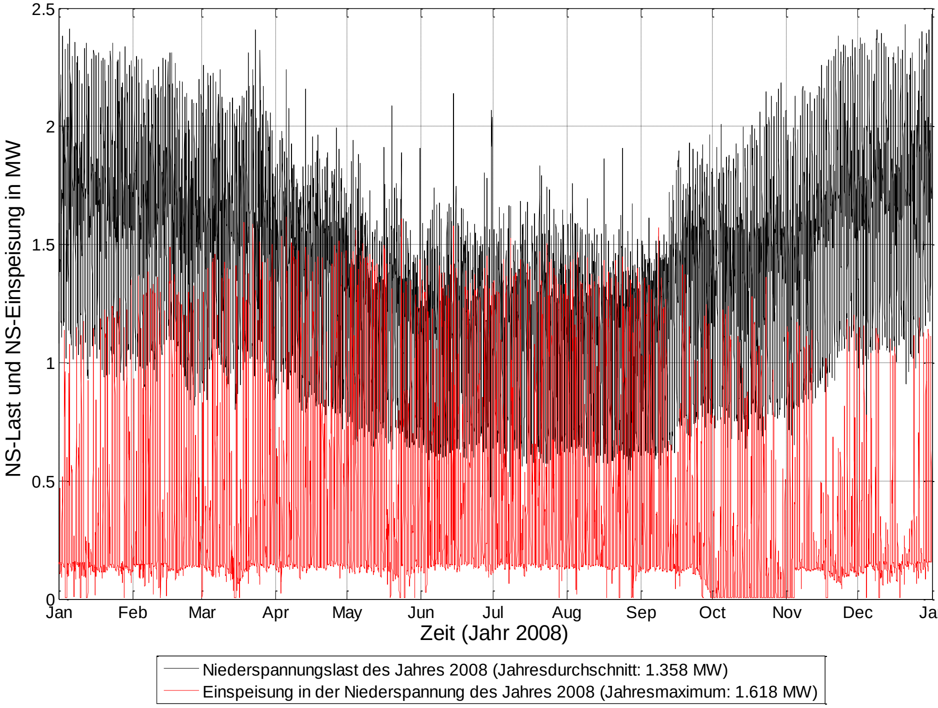
Source: Y.-M. Saint-Drenan 2010 (IWES)

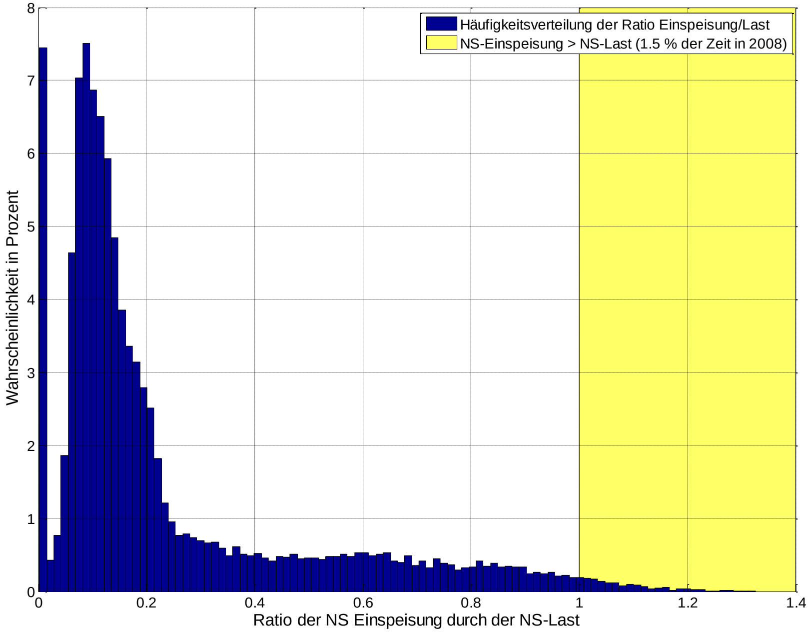
Sources: Braun 2010, IEA PVPS Task 14 Workshop

High Penetration In Germany

Example Circuit

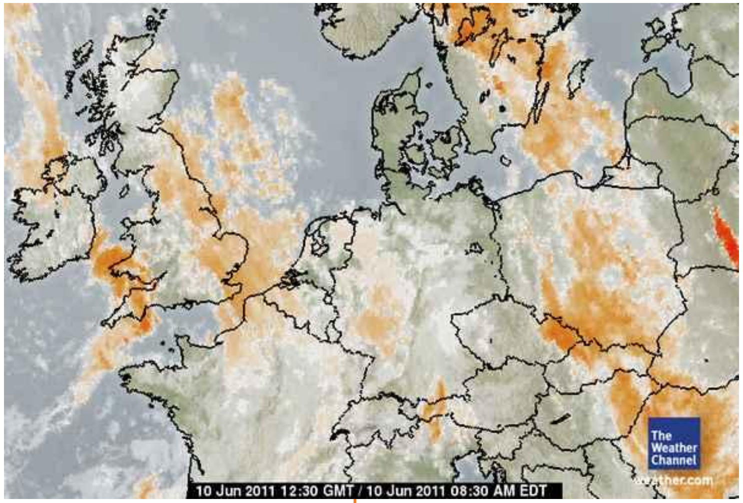
- Data from 2008
- PV to average load ratio: 1.2 (~ 68% PV to peak load)
- PV export up to 1.25 times load; PV > load 1.5% of the time (130 hours / year)





Source: Y. M. Saint-Drenan

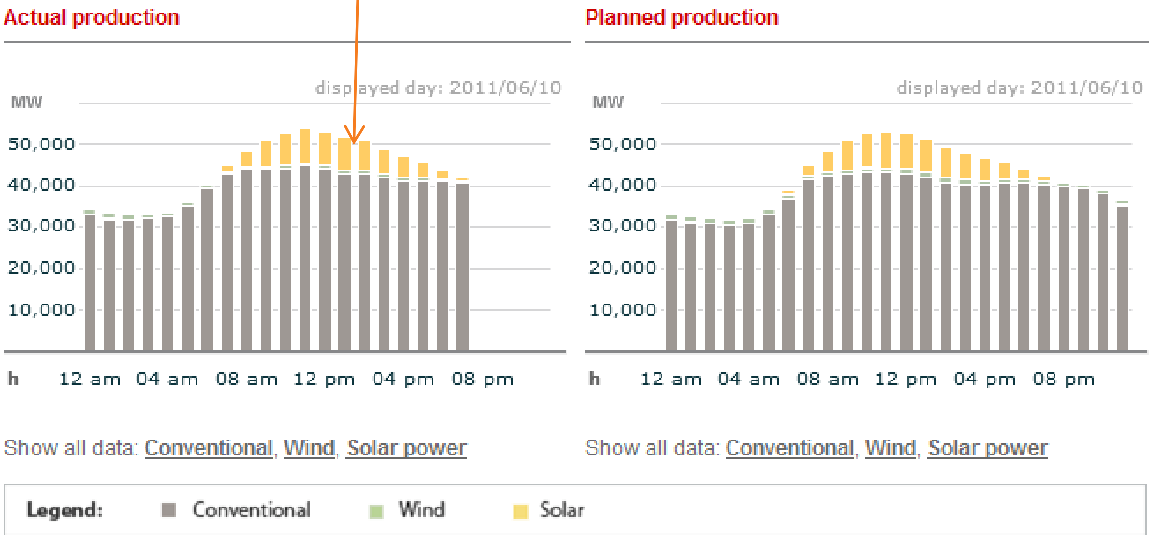
Regional Output – Partly Cloudy Conditions



Aggregate output, across Germany, flattens demand peak – even on a cloudy day.

Forecast accuracy is also notable.

EEX
6/10/2011



Actual production

Show all data: Conventional, Wind, Solar power

Planned production

Show all data: Conventional, Wind, Solar power

SunPower Corporation

How Is Germany Managing This Much DG?

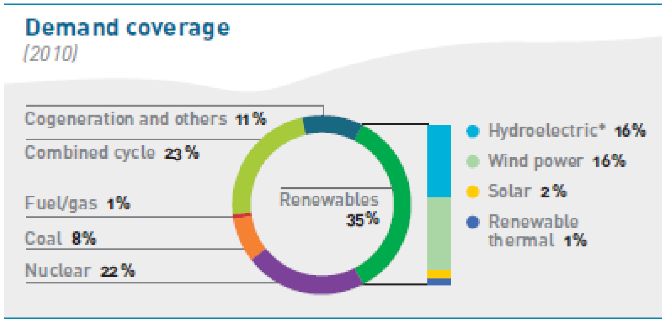
- No control or ride-through requirements until 2009 – MV systems
- MV requirements apply to ~20% of new systems installed since that time.
    - Real & reactive power control, fault ride through (FRT), over-frequency droop
- Low Voltage Directive recently came into effect
    - Similar requirements to MV, except no low voltage ride-through.
- Management via low cost ripple control – simple, unidirectional.
- German requirements anticipate needs to integrate 52 GW of PV by 2020

Best Practices In System Operations

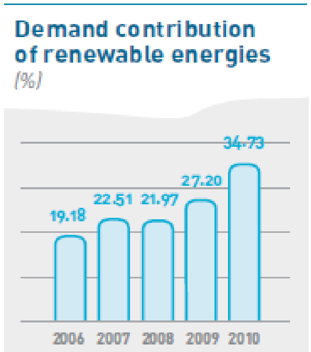
Red Electrica - Spain

- 18% VER in 2010 - 35% renewables overall
- Limited interties
- Similar peak load to CAISO
- Operations Center (CECRE) key for effective renewables integration
- CAISO new operations center & renewables desks modeled after CECRE

"This centre, pioneer in the world, allows an increased integration of renewable energy into the system…without jeopardizing the security and the quality of supply" – Red Electrica 2010 Annual Report

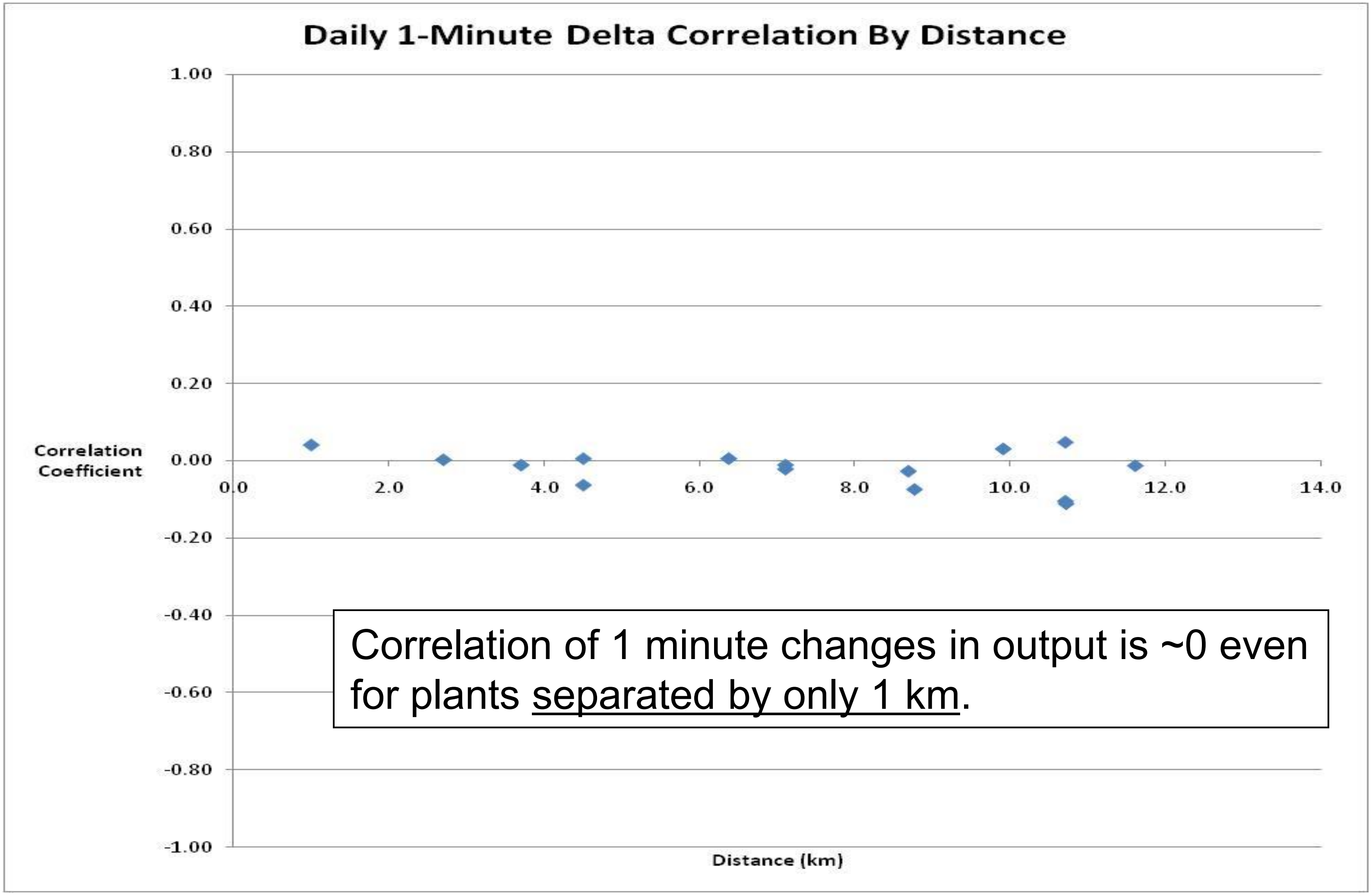


* includes the pumped storage generation and hydroelectric production of the ordinary and special regime.



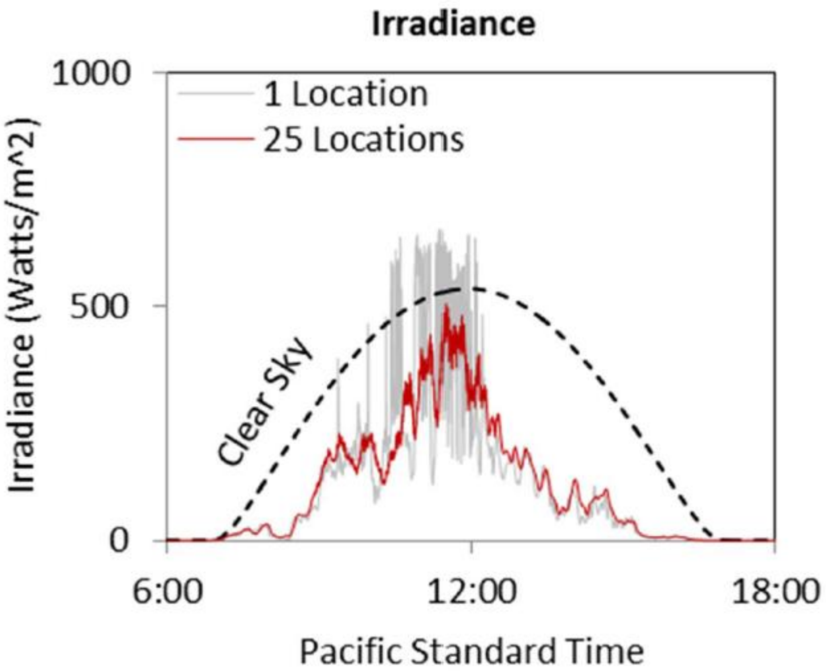
Incluye eólica, hidráulica, solar y térmica renovable

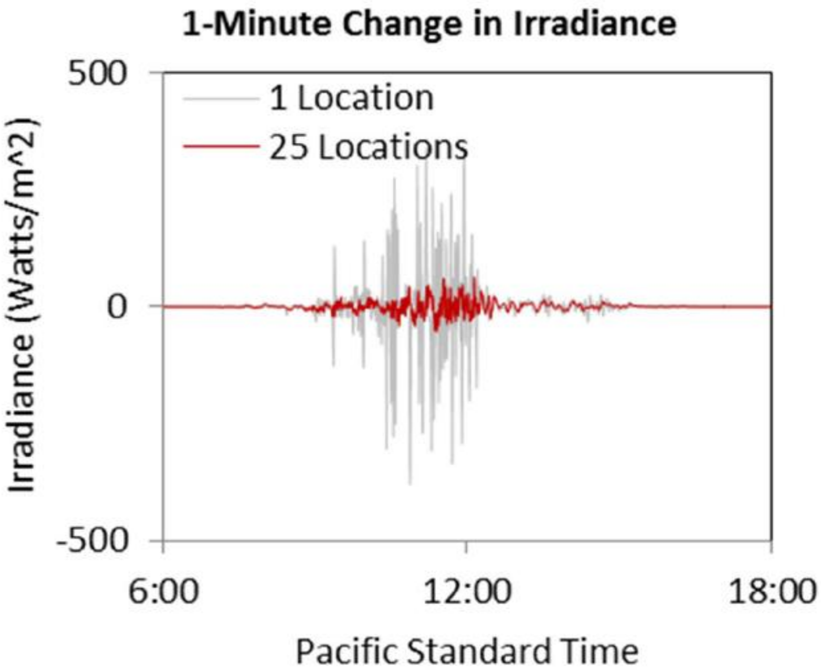
Why? 1-Minute Changes Are Uncorrelated



Correlation of 1 minute changes in output is ~0 even for plants separated by only 1 km.

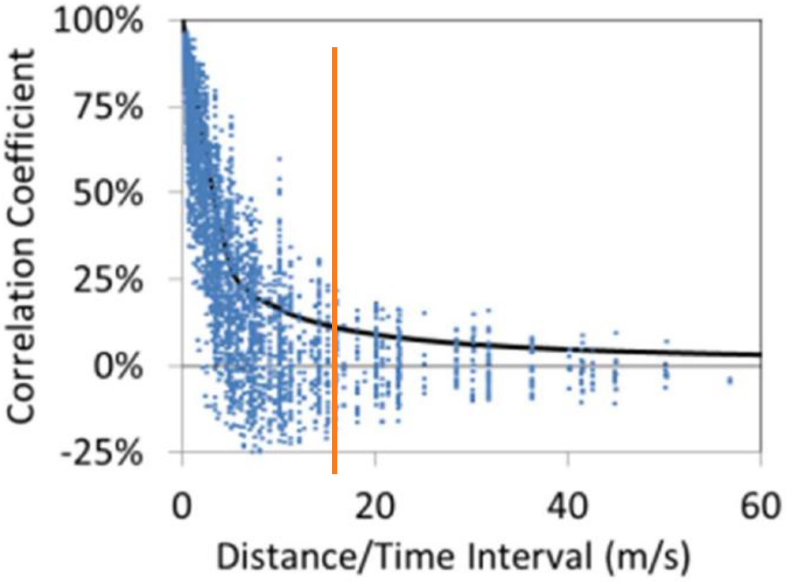
More Examples of Diversity Over Short Distances



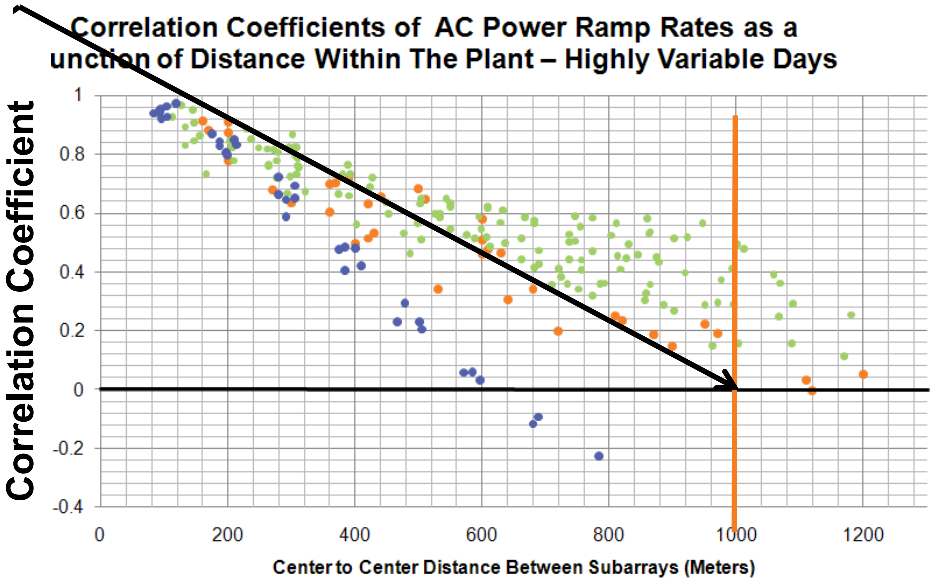


Recent findings By Clean Power Research based on irradiance sensor network on 4 km^2 footprint

More Examples of Diversity Over Short Distances



**Coefficients at 1 km
for 1 minute delta**



Analysis by Clean Power Research based on 25 node irradiance sensor network on 4 km^2 footprint (Napa CA), high variability day

Analysis of 1-minute deltas on high variability days from 3 operating mid-size plants (10 MW – 25 MW) in desert, tropical, and midwestern climates

- Consistently, correlations of 1-minute deltas approach zero at ~1 km (+/- 500 m?).
- Zero-correlation distance for 1-second deltas could be as small as 20 meters.
- Geographical diversity likely mitigates voltage impacts on distribution systems.

Changes (Replete With Acronyms) Are Coming!

- **NERC Integration of Variable Generation Task Force (IVGTF)**
  - Detailed reports addressing all of these topics and many more are in progress, or already published.
  - Focused on transmission interconnection, but addresses changes needed with high penetration DG that will impact bulk electrical systems.
- **FERC Variable Energy Resource (VER) NOPR / WECC EIM**
  - Both tackle interplay between operational practices and integration costs; NOPR proposes that TSOs be able to recover integration costs if operations are modernized.
- **IEEE 1547 Updates**
  - Addresses technical standard changes needed to better accommodate high penetration DG.
- **FERC SGIP** (model for California Rule 21 and many others)
  - IREC proposing updates to address PV specific issues that can pose unnecessary barriers to achieving higher penetration of distributed PV.
- **BDEW LV Directive / EEG**
  - Extension of many of the BDEW MV Directive requirements to all PV systems (depending on size)
  - New curtailment / grid mgmt rules announced early June, apply to < 100 kW systems.
- **Efforts Towards Single EU-wide Electricity Market**
  - Requires harmonization of grid codes, e.g. ENTSO-E effort