Impacts of High Variable Renewable Energy (VRE) Futures on Electric-Sector Decision Making

Joachim Seel, Andrew Mills, Ryan Wiser

Lawrence Berkeley National Laboratory

Presentation at International Conference on Energy Systems Integration

December 05-06, 2017

Golden, CO

This project is funded by the Office of Energy Efficiency and Renewable Energy (Strategic Programs Office) of the U.S. Department of Energy

Table of Contents

Introduction:
Evidence of VRE Price Changes

When the future doesn't follow trend lines of the past…

Australia

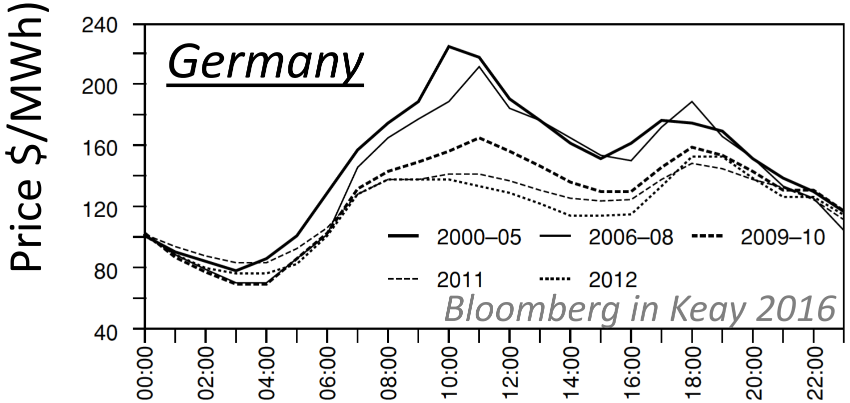
◆High VRE can change:

- ❑ the timing of when electricity is cheap or expensive,
- ❑ the locational differences in the cost of electricity, and
- ❑ the degree of regularity or predictability in those costs.

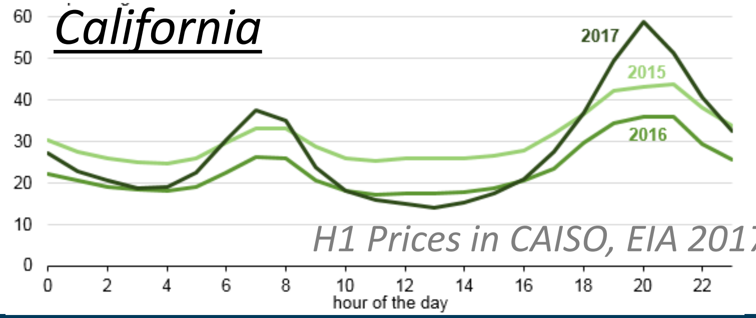
◆Many of these changes can be observed through changes in the patterns of wholesale prices, both internationally and in some regions in the US, e.g.

- ❑ Changes in TOU periods at the CAISO
- ❑ "Free" electricity at night in Texas

Gilmore et al 2015

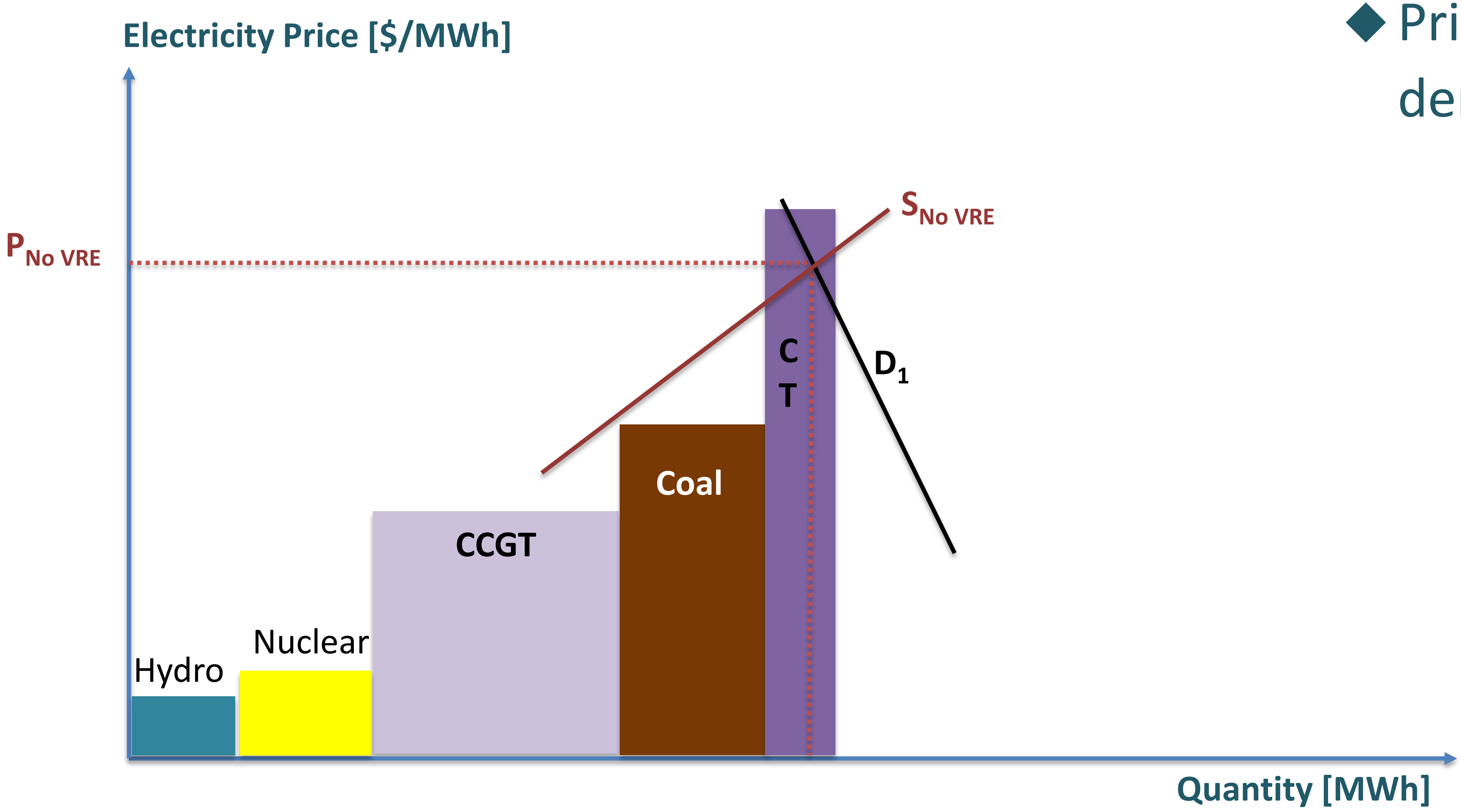


Bloomberg in Keay 2016



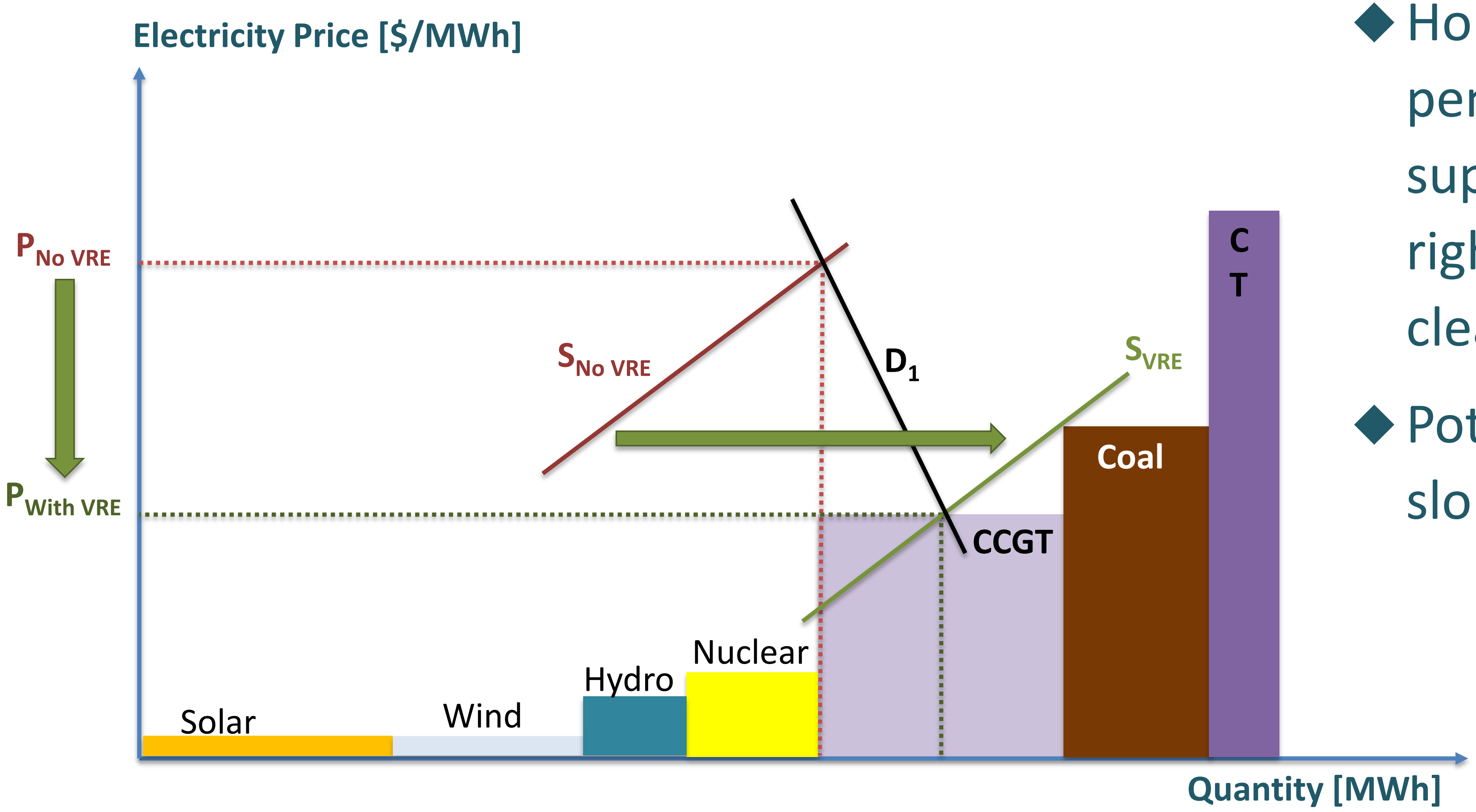
H1 Prices in CAISO, EIA 2017

Theoretical Background
Price Formation with VRE



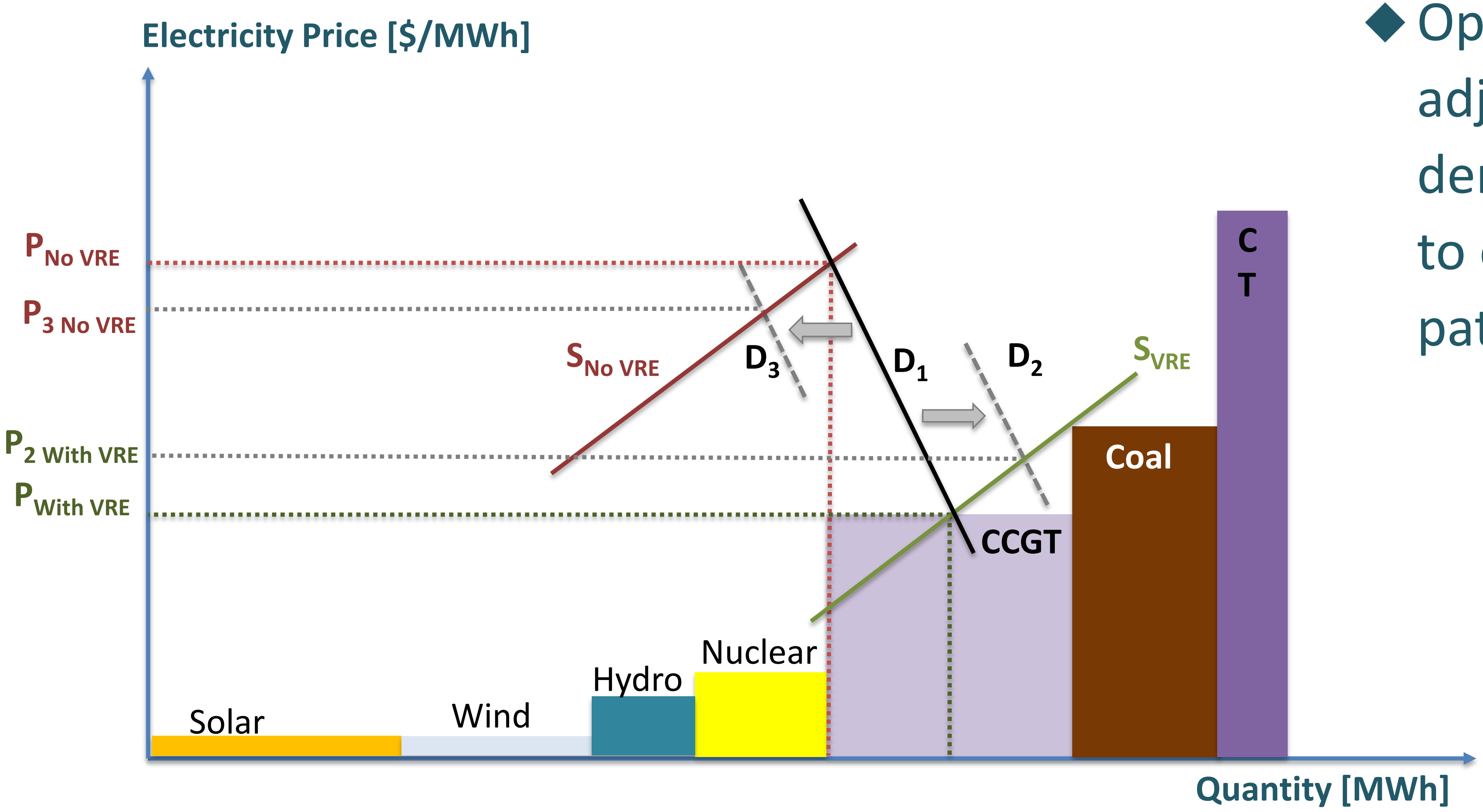
- Price set by variable demand levels

Theoretical Background
Price Formation with VRE



- Hours with high VRE penetration shift supply curve to the right and lower clearing prices
- Potential supply slope change

Theoretical Background
Price Formation with VRE



- Opportunity to adjust longer-term demand in response to changed price patterns

Research Motivation and Objective

Research Objective

Will electric-sector decisions that are based on past assumptions still achieve their intended objective in a high VRE future?

Demand-Side Decisions	Supply-Side Decisions
Choice of Energy Efficiency Portfolios	Incentives for Nuclear Revenue Sufficiency, Flexibility Retrofits
Appliance Standards promoting Electric or Gas Water Heaters	Investing in Combined Cycle Gas Turbines or Reciprocating Engines
Demand Response Service Design	Cost-effectiveness of Energy Storage and Capability Selection
Location choices of EV charging infrastructure	Hydropower Relicensing under alternate Water Flow Regimes
Advanced Commodity Production Processes	
Retail Rate Design	

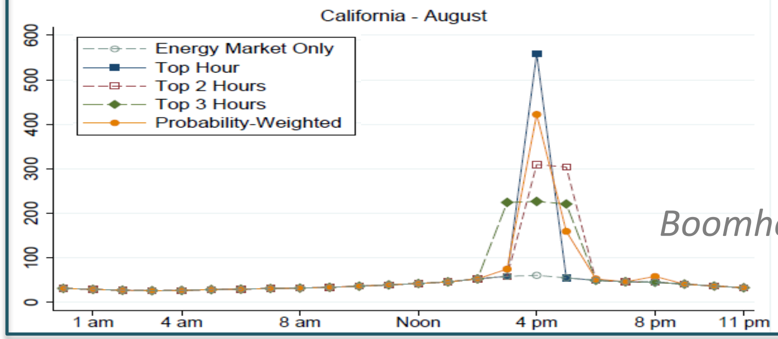
Example: Energy Efficiency Portfolios

- Decision Type
  - Approve EE portfolios to decrease energy consumption, curb demand growth, reduce electric system needs in most cost-effective manner
- Decision Analysis
  - National Standard Practice Manual suggests forward-looking, long-run marginal costs to evaluate EE cost-effectiveness
  - Wide variety of cost-effectiveness evaluation practices. Nascent move to time-dependent valuation instead of average prices, opportunity to incorporate forward-looking scenario analysis

Traditional Design

- Demand peak reductions via Energy Star Residential Air Conditioners that emphasis afternoon savings

Traditional Savings of Residential AC EE retrofits



Boomhower and Davis 2017

High VRE Future

- Lower share of near-constant load reduction measures (refrigerators)
- Net-Demand peak reductions that focus on evening savings via residential lighting efficiency measures or street lighting measures

Example: Appliance Standards

- Decision Type
  - Adapt building code design (e.g. CA Title 24) to evaluate electric vs. gas-fired heaters for new/substantially retrofitted buildings
- Decision Analysis
  - Time-dependent-valuation of gas and electricity consumption over 30 years, potentially via scenario-analysis
  - Broad range of value stream inclusion (energy, capacity, emissions, transmission, losses, RPS)

Traditional Design	High VRE Future
Preference for gas-fired water heaters	Preference for electric water heaters
No coupling to electric market dynamics	Strategic use of load to participate in demand-response programs

Example: Nuclear Flexibility Incentives

- Decision Type
  - Increase R&D on flexible nuclear demand design and operations
  - Address technical regulations on nuclear plant operations
  - Provide financial incentives to keep nuclear plants operating
- Decision Analysis
  - Compare revenue options of traditionally operating and "flexible" nuclear plants

Traditional Design	High VRE Future
• Baseload nuclear plant with near constant power output and annual capacity factor near 100% • Little ramping capabilities and no participation in ancillary service markets • No special financial incentives to support O&M costs	• Nuclear plant operations with significant hours of non-maximum power output • Regular ramping within limits, potentially only seasonal operation

Research Design

Research Framework Design

- Performing a **marginal benefit analysis** using marginal prices and emissions
  - Developing wholesale price series and emission rates for high VRE future in 4 US regions
  - Analyzing value impacts on demand-side (Year 2) and supply-side assets (Year 3)
- Partnering with consulting firm LCG for model development
  - Capacity expansion model to establish 2030 generator portfolio based on social cost minimization
  - SCED co-optimizes congruent hourly energy, capacity and ancillary service prices
- Guidance via a **Technical Review Committee** of subject matter experts

Low VRE	High VRE
• **Low VRE** Future with Generation Share frozen at 2016 levels	• **Balanced VRE** (20% Wind, 20% Solar) • **High Wind** (30% Wind and at least 10% Solar) • **High Solar** (30% Solar and at least 10% Wind)

VRE Penetration Scenarios in 2030

Scenarios

- Frozen VRE (Generation %) Future
- High VRE Futures
  - Balanced VRE (20% Wind, 20% Solar)
  - High Wind (30% Wind and at least 10% Solar)
  - High Solar (30% Solar and at least 10% Wind)

Assumptions

- Maintain realism in scenario design
  - No reduction of VRE generation below 2016 levels
- Limit price distortion through leakage to neighboring markets
  - Surrounding market penetration of 40% VRE
- Limit price effects that are primarily congestion related
  - Expand intra-zone transmissions to keep VRE curtailment of <3%
- Adequate representation of behind-the-meter PV
  - 75% of generation comes from large-scale PV, 25% from distributed PV

Capacity Expansion Model to select Generator Portfolios for 2030

- Entry of new generators and exit of existing generators is uncertain and requires modeling choices
- Background on Capacity Expansion Model and Optimization Tool Gen-X:

Capacity Expansion
based on social cost minimization,
capital costs covered with revenues from the power markets (energy, capacity and ancillary services)

Capacity Retirement
based on cost recovery if unable to serve fixed and variable O&M costs

- Ancillary Service requirements change with VRE penetrations
- Emission costs drive clearing prices → exogenous projections of permit prices by planning entities
- Load levels determine demand for existing and new generators→ load forecasts by planning entities
- Fuel prices affect generator investment choices and merit order dispatch → forecasts based on Henry Hub/ EIA data

SCENARIOS: Generator Retirements due to VRE Expansion

Unbalanced scenarios excluding VRE induced retirements
- Overcapacity beyond reserve margin requirements
- suppressed average prices
- less price variability

Balanced scenarios including VRE induced retirements
- Tighter supply capacity
- higher average prices
- Higher price variability

Unit Commitment Model to derive hourly data series

- Background on Unit Commitment Model U-Plan
  - Co-optimized energy, capacity and ancillary service prices via SCED for price congruency
  - Zonal regional resolution given uncertainty about 2030 prices

- Consistent Hourly Data Series for the year 2030
  - Wholesale Energy Prices
  - Capacity Prices (where applicable)
  - Ancillary Service Prices (Regulation Up/Down, Spin Reserves, Non-Spin Reserves)
  - Marginal Emission Rate (CO2)

Regional Case Studies

SPP

- 2016 VRE Deployment:
  - Wind 9-29% (19%) of generation (~16 GW capacity),
  - Solar 0.1% of generation
- No RPS mandates driving additional renewables by 2030

NYISO

- 2016 VRE Deployment:
  - Wind 3% of generation (1.8 GW nameplate),
  - Solar 0.8% of generation (0.3 GW, incl BTM PV)
- Clean Energy Standard of 50% by 2030

CAISO

- 2016 VRE Deployment:
  - Wind 7% of generation (5.6 GW nameplate),
  - Solar 14% of generation (18.2 GW, incl BTM PV)
- SB 350 requires 50% RPS, projections yield 13.5% wind and 27.5% solar

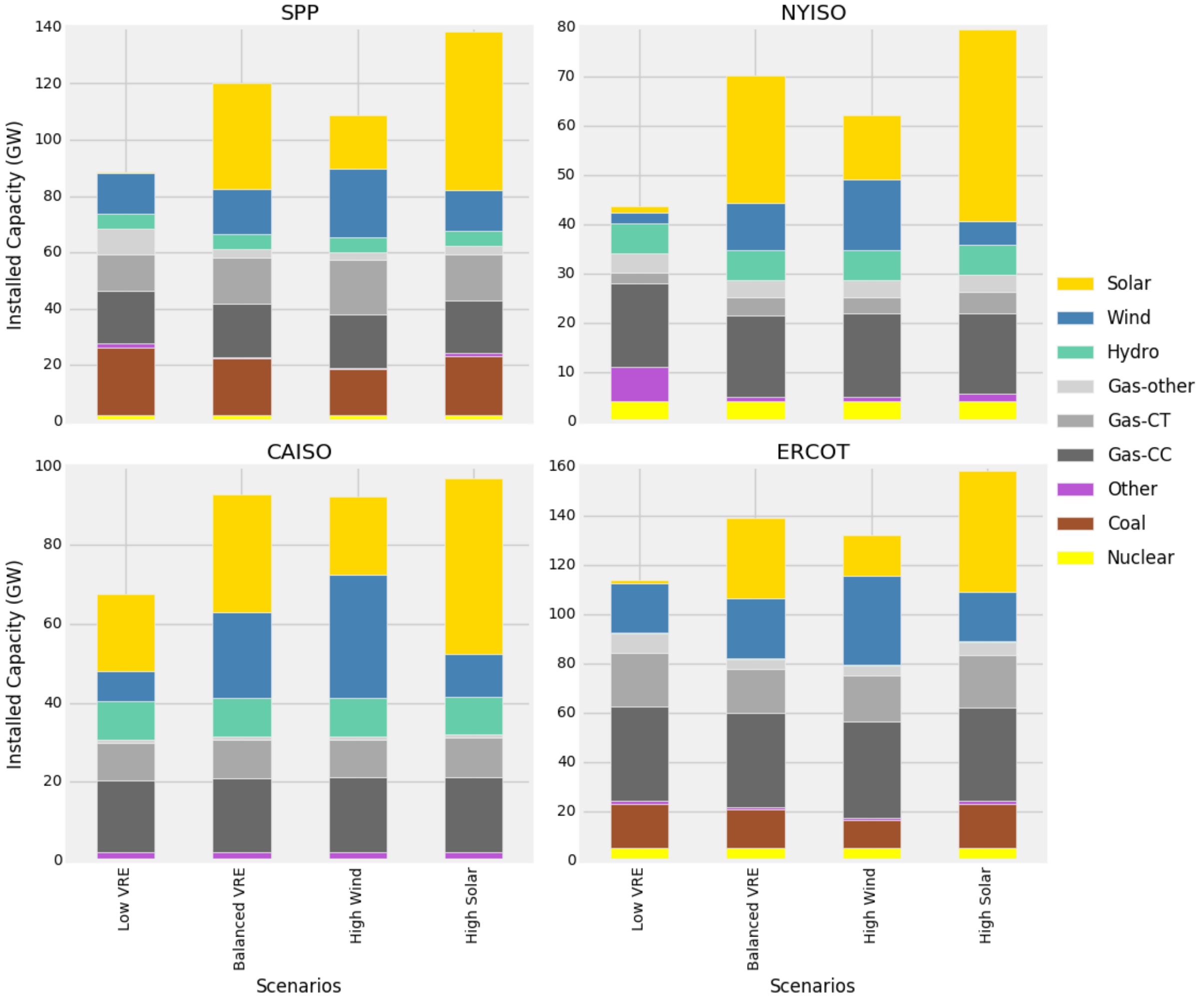
ERCOT

- 2016 VRE Deployment:
  - Wind 13% of generation (20.3 GW nameplate),
  - Solar 0.25% of generation (1.2 GW, incl BTM PV)
- No wind/solar/carbon mandates driving deployment in 2030

High Level Results

VRE expansion leads to modest retirement of firm capacity of 4-16%, especially coal, oil and steam turbines

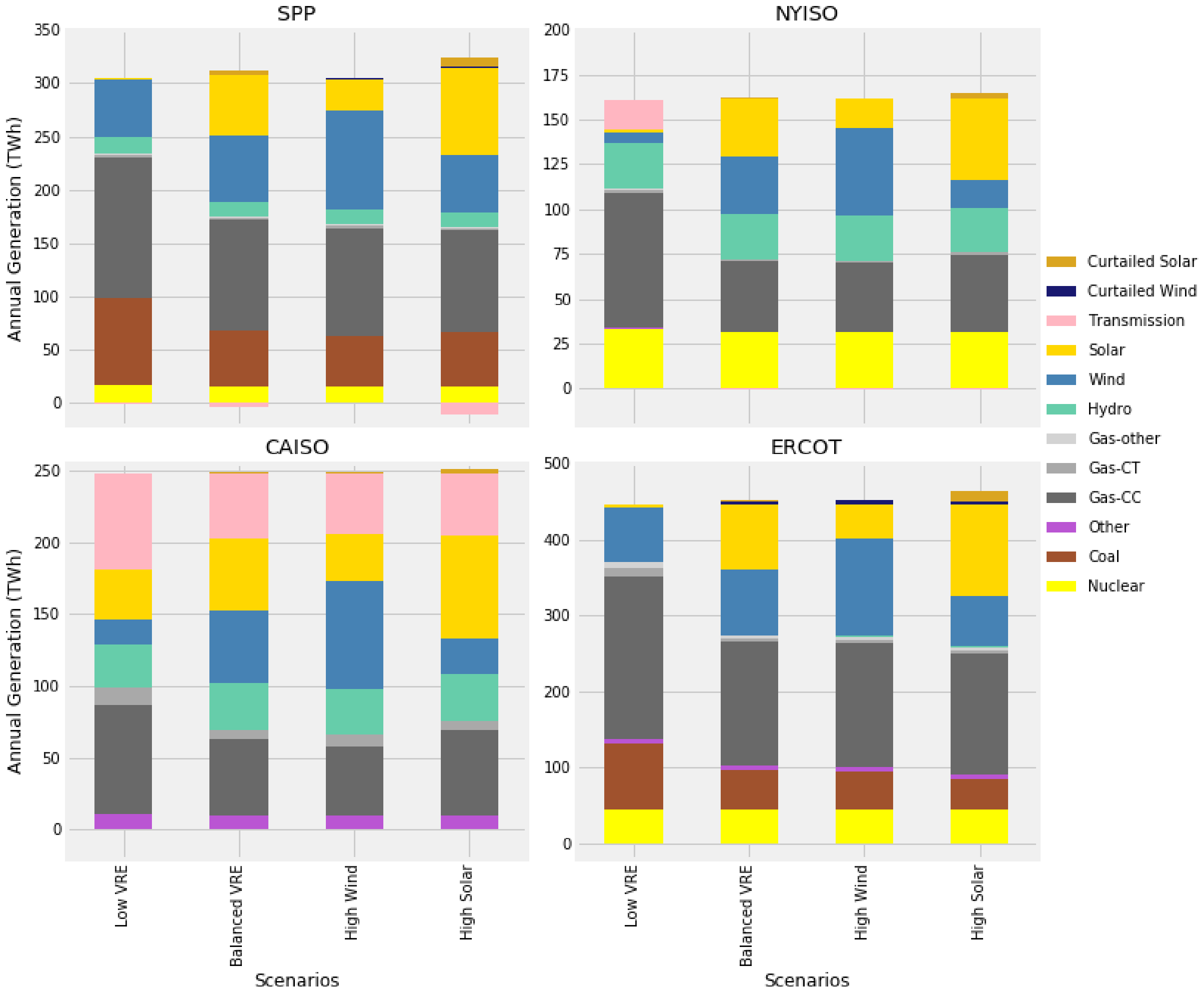
Capacity Comparison across Regions



- **SPP: firm capacity reduction by 9-12%**
  - Retirement of Coal (4-8GW) and Other Gas (7GW, e.g. steam turbines)
  - largely offset by Gas CT growth (4-7GW)
- **NYISO: firm capacity reduction by 13-16%**
  - Oil retirement (5+ GW)
  - partially offset by Gas CT growth (1-2GW)
- **CAISO: firm capacity growth by 2-4%**
  - Little overall changes in capacity
  - minor growth in Gas CC (0.4-0.8GW) and Gas CT (0.4GW)
- **ERCOT: firm capacity reduction by 4-14%**
  - Coal retirement largest in **wind** scenario (7GW) - none in **solar**
  - Largest Gas CT retirement in **balanced** (4GW vs. 1GW in **solar**)
  - Gas CC largely stable, growth by 1GW in **wind** scenario

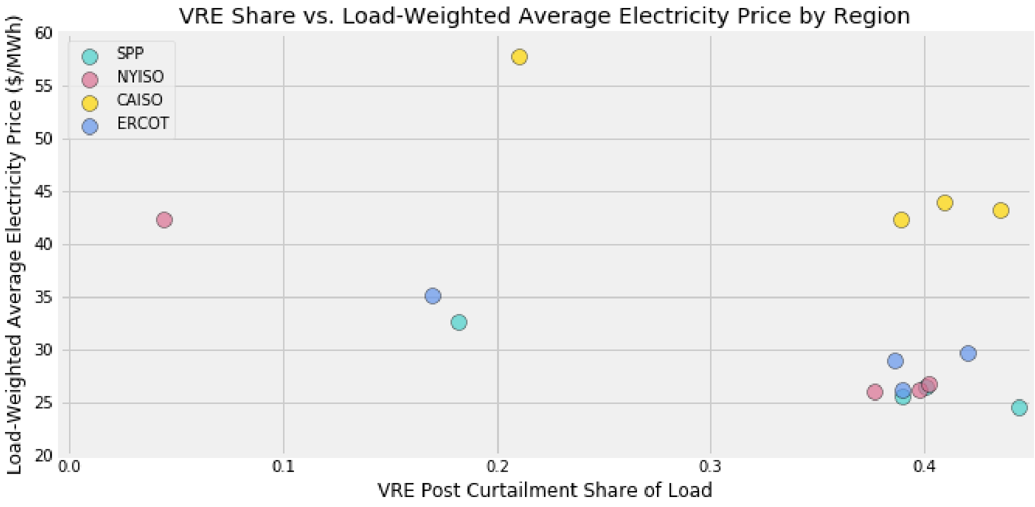
VRE generation offsets 25-50% of fossil generation, especially coal and CC natural gas

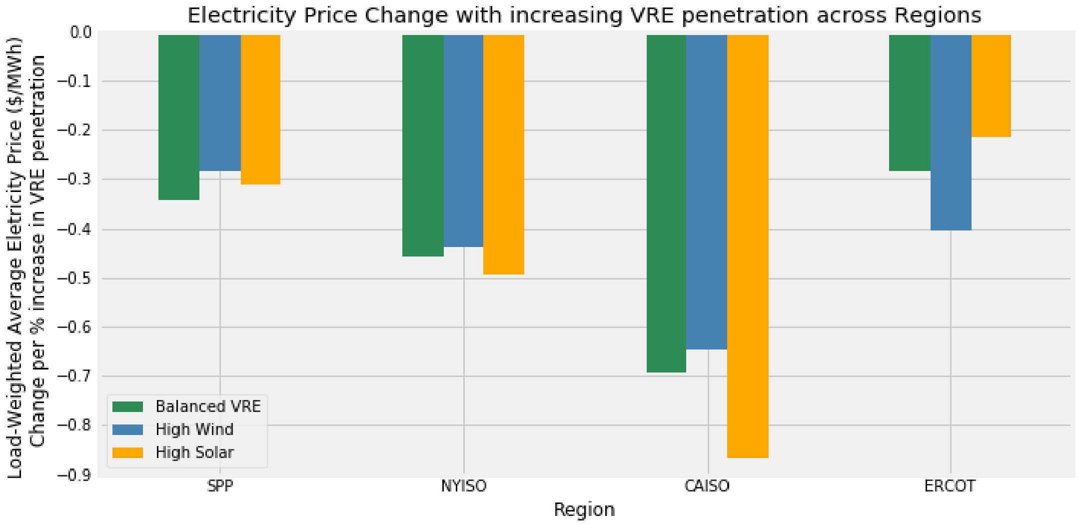
Generation Comparison across Regions



- SPP: fossil generation reduction by 27-32%
  - Reduction in Coal and Gas CC generation (30-35TWh each)
  - Minimal changes in Gas CT
  - 9TWh of solar curtailment, 10TWh of export in solar scenario
- NYISO: fossil generation reduction by 44-50%
  - Reduction in Gas CC (32-35TWh) and imports (17TWh)
  - minimal drop in Gas CT
- CAISO: fossil generation reduction by 25-33%
  - Reduction in Gas CC (esp. in **wind** scenario: 17-28 TWh), imports (22-26 TWh) and Gas CT (4-6 TWh)
  - Difficult to assess composition of imports as we lack fuel information
- ERCOT: fossil generation reduction by 30-34%
  - Reduction in Coal (35-46TWh) and Gas CC (50-55TWh), esp. in **solar**, 60-80% Gas CT reduction (more in **wind**/**balanced**)
  - Up to 13TWh of solar curtailment, 5TWh of wind curtailment

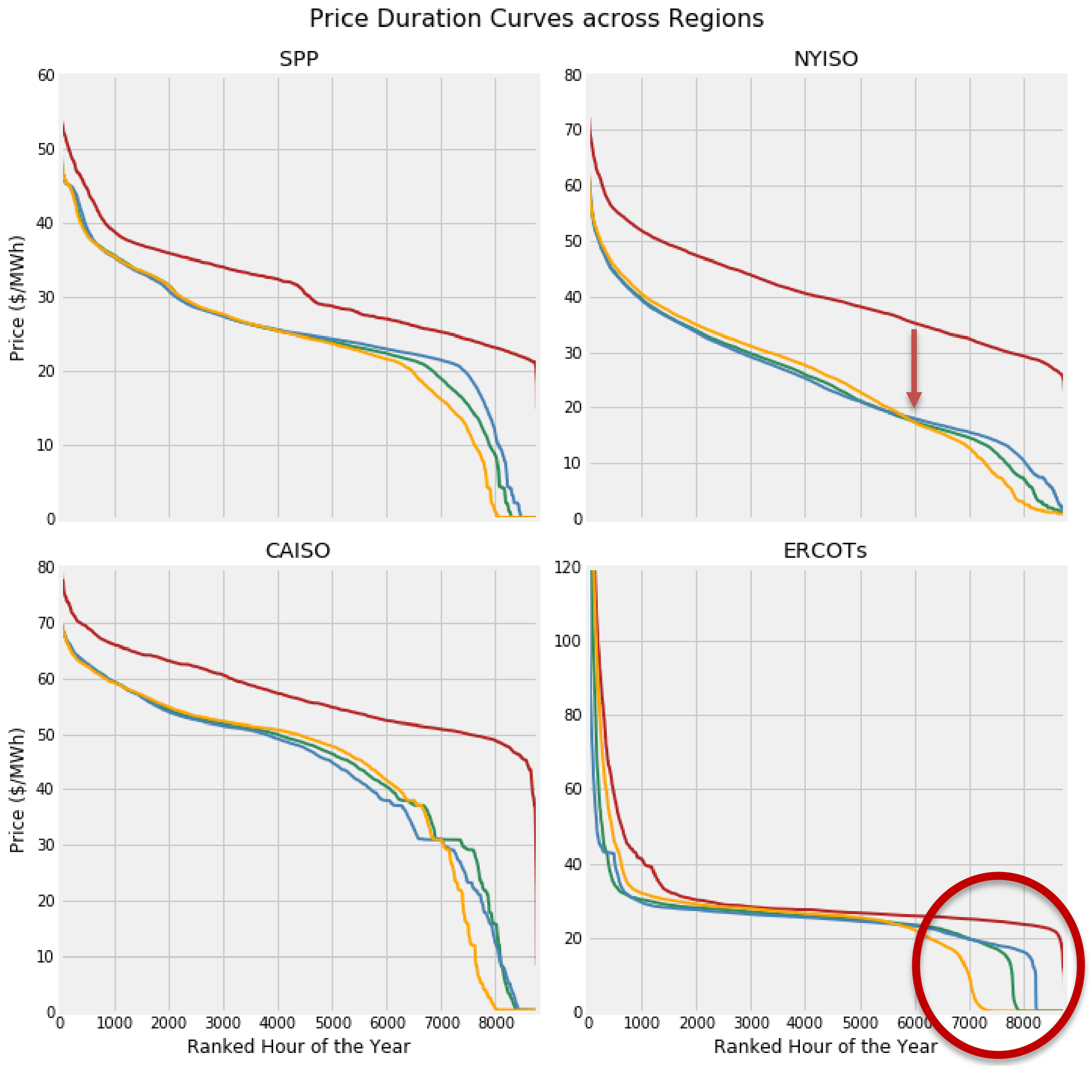
VRE penetration increase reduces average electricity prices

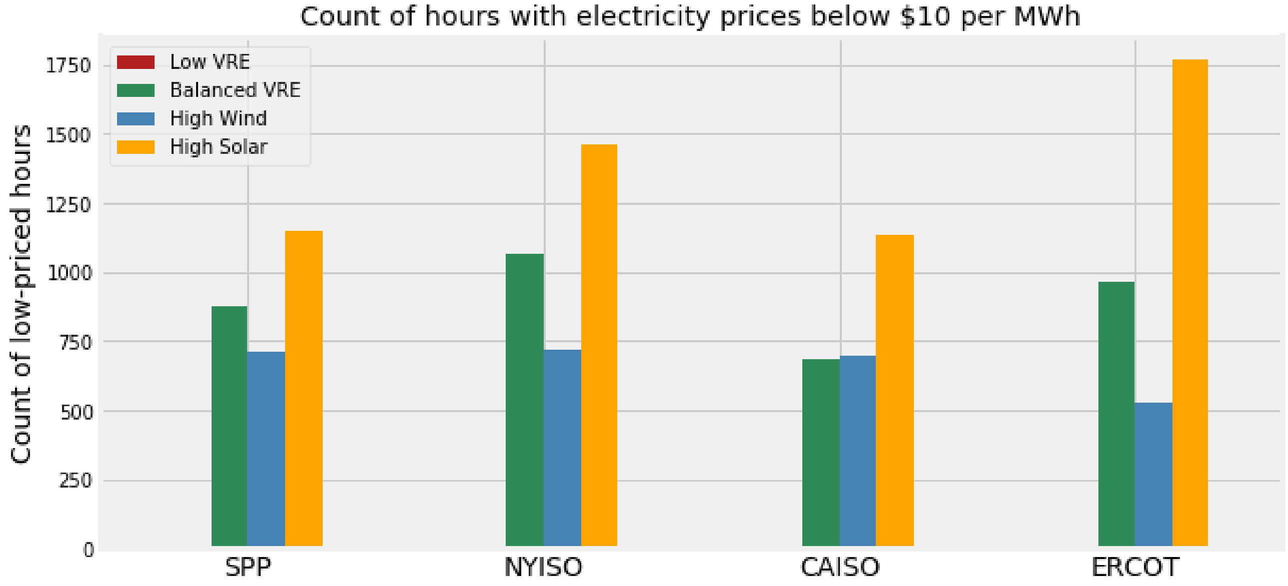




- Load-weighted average electricity prices decrease with higher VRE penetration by $5 to $16 relative to low VRE baseline, depending on scenario and region
- Accounting for the different starting levels of VRE penetration, the average reduction in electricity is $0.2-$0.85/MWh for each additional % of VRE penetration
- Both findings fall in the general range of the US electricity market modelling literature

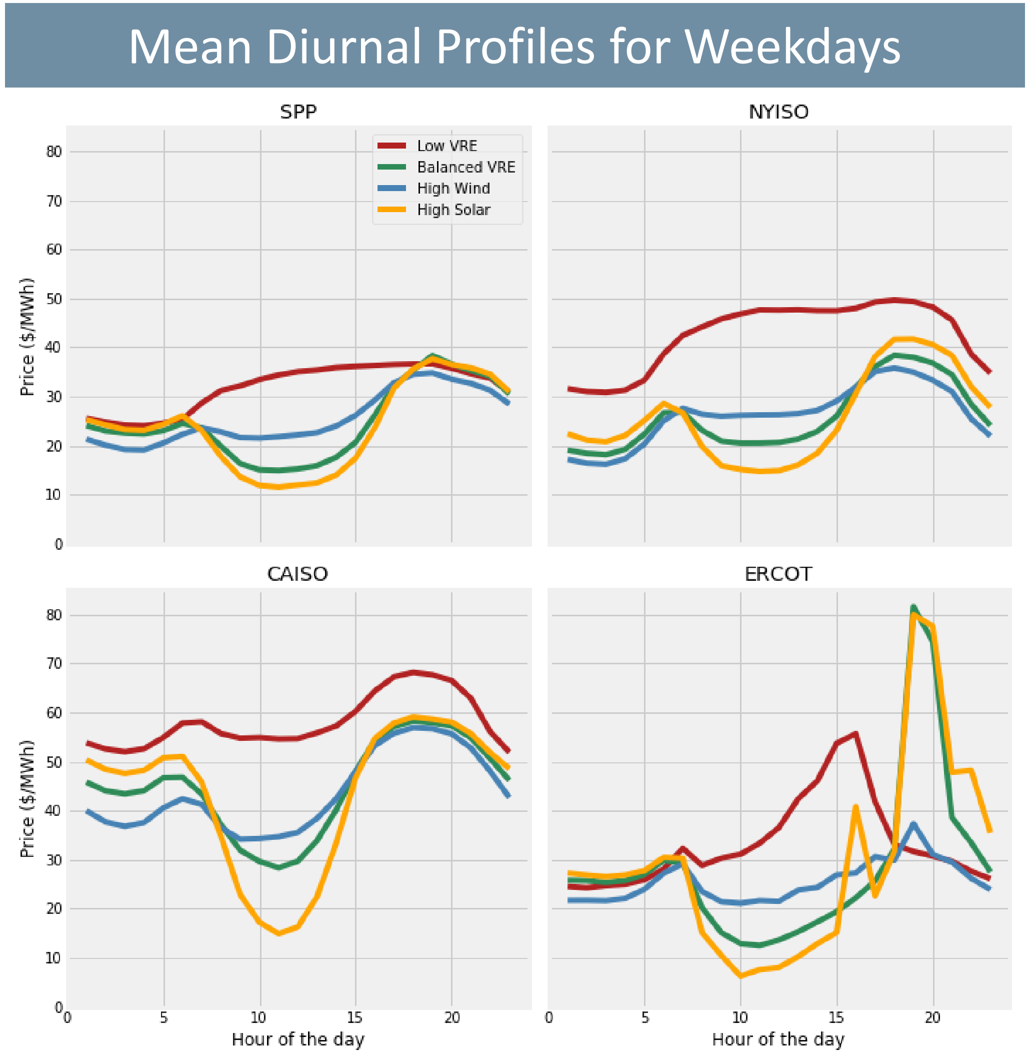
Low energy prices become more common





- In some regions the shape of the price distribution does not change dramatically but is merely shifted downwards (e.g. NYISO)
- Other regions feature a more pronounced 'cliff', highlighting an increase in hours with very low prices (e.g. ERCOT)
- Low prices occur most often in **solar** scenarios

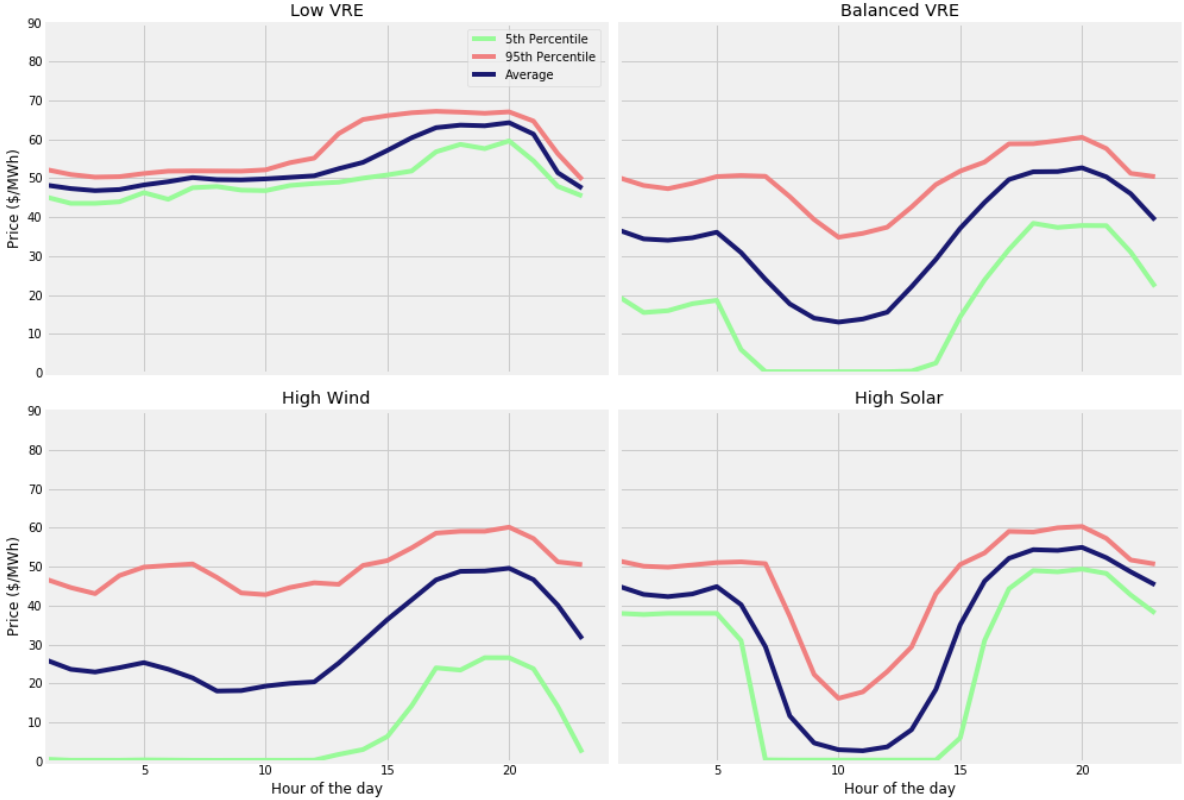
Change in diurnal price profile

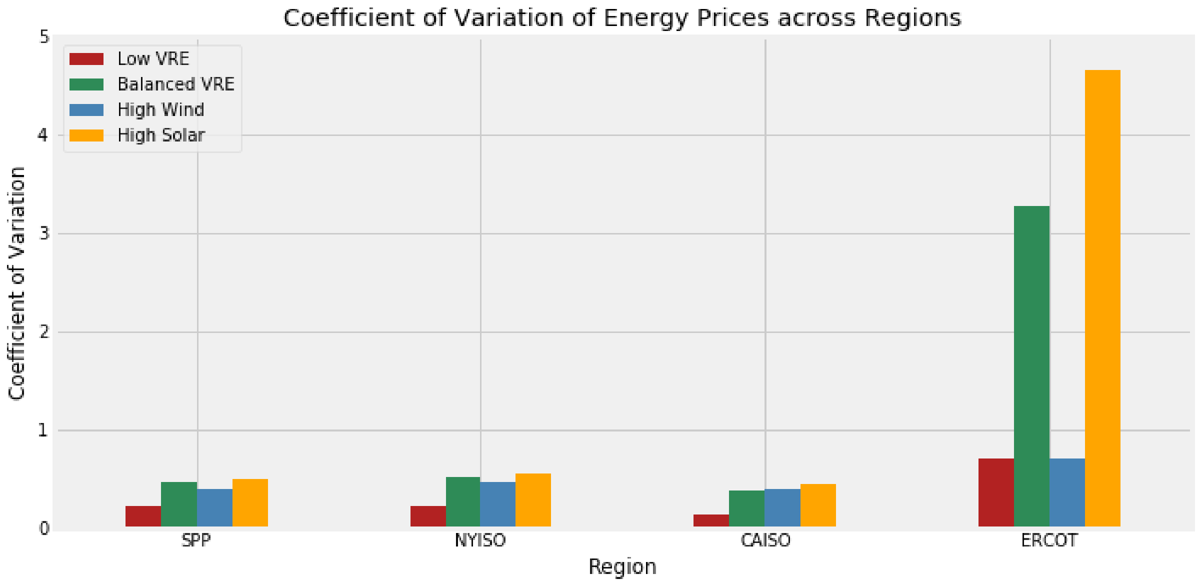


- Substantial decrease in prices over the middle of the day in **solar** scenarios across all regions
- Diurnal profiles vary by season
  - **Morning** Spring: $20/MWh - Fall: $50/MWh in CAISO in **wind** scenario
  - **Afternoon** Spring: $20/MWh – Summer: $40/MWh in NYISO in **wind** scenario
  - **Evening** Winter: $30/MWh – Summer: $200/MWh in ERCOT in **balanced** and **solar** scenario (driven by few high-priced hours)
- Price peaks remain across most seasons in the early evening hours at levels similar to **low VRE** scenario

Increase in Price Volatility

Price Distribution in CAISO in Spring

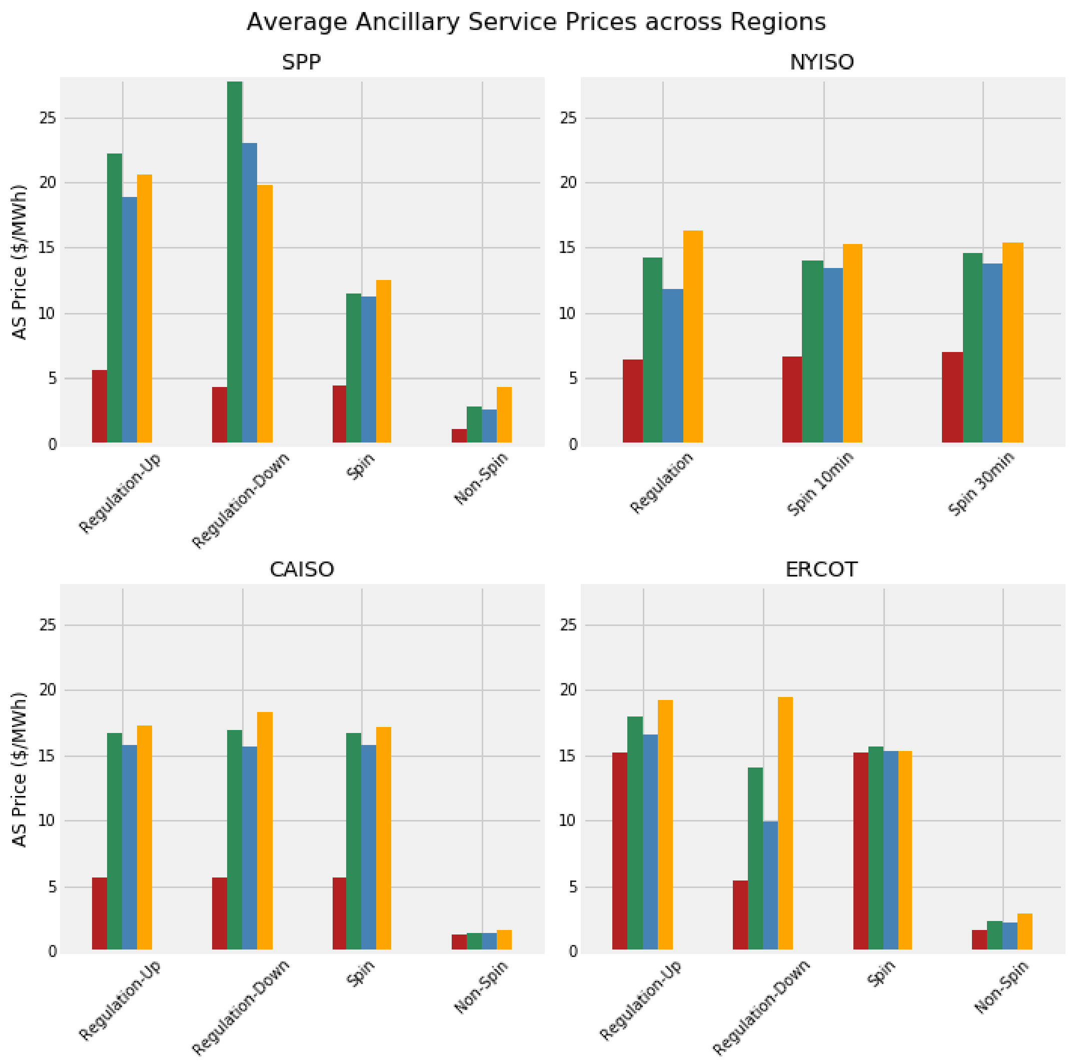




- Wider range in **wind scenario** during early morning hours
- Change in average diurnal profile in **balanced scenario** & 5th-95th range increases during the middle of the day

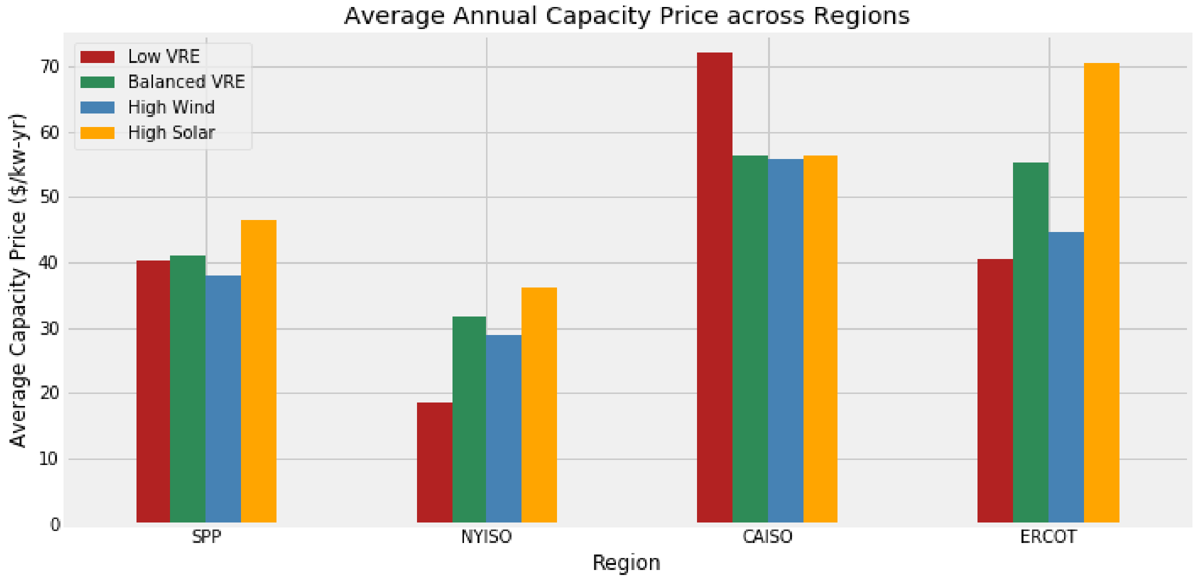
- Coefficient of Variation is normalized standard deviation of prices to facilitate cross-regional comparison
- Price volatility increases across regions from **low** over **wind**, **balanced** to **solar** scenario
- High volatility in ERCOT in part due to few high priced hours ($1000-$9000/MWh) due to Operating Reserve Demand Curve

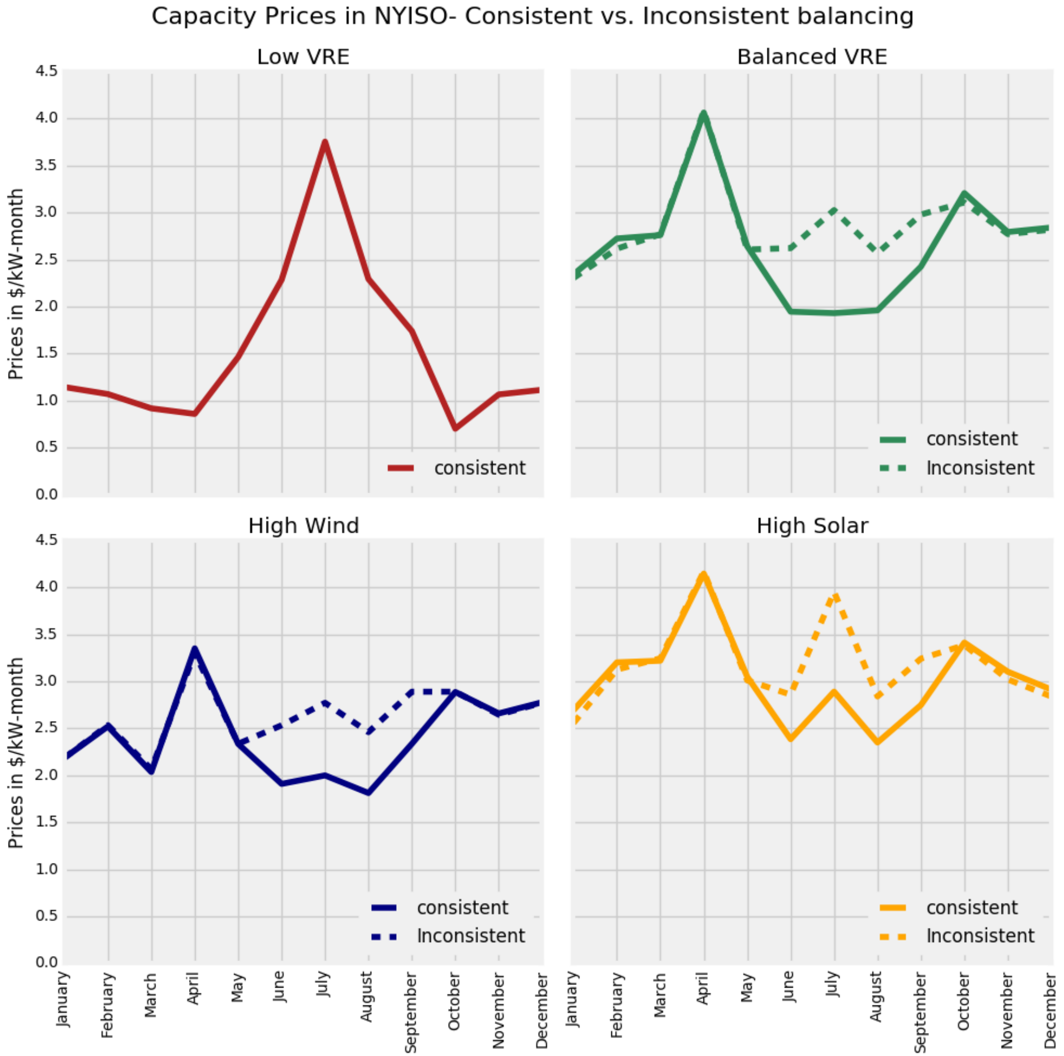
Rise in Ancillary Service Prices



- Average prices for regulation (up and down) and spinning reserves increase by 2-4x across most regions in high VRE future to $15-$20/MWh
- Non-spinning reserves tend to remain at lower prices
- High **solar** penetrations often lead to the strongest increase, with peak prices above $190/MWh in CAISO across all AS-types
- **Balanced** and **wind** scenarios reach occasionally $200/MWh in SPP for downward regulation
- Diurnal AS price profiles and their peaks can change significantly, as do price ranges

Mixed Capacity Price Results across Regions





- Mixed trends in annual averages, solar often leads to higher prices:
  - SPP
  - NYISO and ERCOT
  - CAISO
- Annual averages mask **month-month variation**
  e.g. July in NYISO switches from max to min prices

Outlook

- Remainder of 2017:
  - Finalizing data analysis, publication of briefing slides and technical report
  - Price data potentially publically available
- 2017/2018:
  - Implications of price changes on demand-side assets
- 2018/2019:
  - Implications of price changes on supply-side assets

Questions?

Thank you for your attention!

- Contact
  - Joachim Seel:
  - jseel@lbl.gov 510-486-5087
- Project Team at the Lawrence Berkeley National Laboratory:
  - Andrew Mills
  - Ryan Wiser

Download all of our other solar and wind work at:

http://emp.lbl.gov/reports/re

Follow the Electricity markets & Policy Group on Twitter:

@BerkeleyLabEMP

This project is funded by the

Office of Energy Efficiency and Renewable Energy

(Strategic Programs Office)

of the U.S. Department of Energy