IRP Modeling Advisory Group Webinar

Core Modeling Assumptions for 2019-20 IRP Reference System Portfolio Development

June 17, 2019

I. Introduction

Modeling Advisory Group (MAG) Background

- The MAG provides an open forum for informal technical discussion and vetting of data sources, assumptions, and modeling activities undertaken by CPUC staff to support the IRP proceeding (R.16-02-007)
- Participation in the MAG is open to the public, subject to the terms of the charter, and communication of events and materials is through the IRP proceeding service list
- Feedback received during and following MAG webinars and workshops inform staff work products that are later introduced into the formal record of the IRP proceeding

Purpose and Scope of Webinar

- Purpose:
  - Present development of common core model inputs
  - Request for parties to vet core model inputs and provide feedback, especially for those parties planning to conduct production cost modeling to inform the IRP process
  - Present draft process and schedule for 2019 IRP Reference System Portfolio development – focusing on modeling and calibrating major outputs (e.g. production cost, curtailment, emissions, etc.) between RESOLVE and SERVM
  - Propose approaches for incorporation of transmission capability and upgrade data from CAISO in 2019-20 IRP
- Out of scope:
  - 2018 IRP Preferred System Plan Decision (D.19-04-040)
  - Proposed Scenarios and Sensitivities for 2019-20 IRP modeling
  - Candidate resource cost and potential updates

Webinar Agenda

Item	Time *
I. Introduction, Purpose and Scope, Process for 2019 Reference System Portfolio Development	10:00 – 10:10am
II. Overview of Reference System Portfolio Development	10:10 – 10:30am
III. Data Development for Baseline Resources: Conventional, Renewables, and Storage	10:30 – 11:00am
IV. Use of IEPR Electric Demand and Demand Modifiers Datasets, plus Other Key Inputs	11:00 – 11:20am
V. Development of Wind and Solar Hourly Profiles in SERVM	11:20 – 11:55am
VI. Revisions to Modeling of NW Hydro Imports	11:55 – 12:10pm
VII. Approaches for Incorporation of Transmission Inputs	12:10 – 12:30pm
Adjourn	

**Time allocated for agenda items includes Q&A*

IRP Proceeding Major Milestones 2019-20

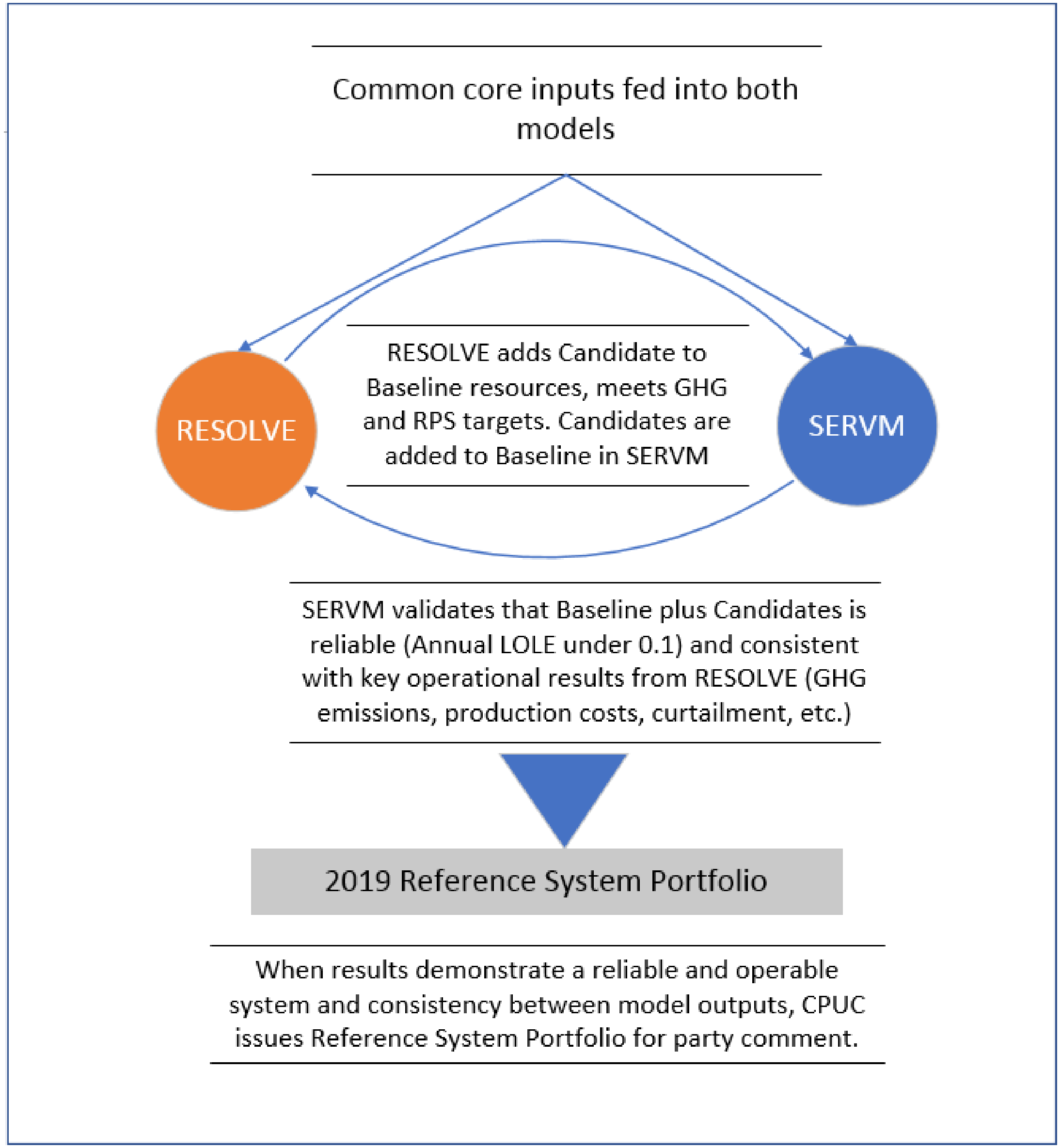
Activity	Estimated Date
2018 Preferred System Plan LSE Progress Status Data Request due (D.19-04-040)	August 16, 2019
Formal release of 2019 Filing Requirements Staff Proposal	August 2019
Formal party comments on Filing Requirements Staff Proposal	September 2019
Formal release of Proposed 2019 IRP Reference System Plan	October 2019
Formal party comments on Reference System Plan	November 2019
Formal release of 2019 IRP Reference System Plan Proposed Decision	December 2019
Formal party comment on 2019 Reference System Plan PD	January 2020
Commission Decision on 2019 Reference System Plan	February 2020
Transmittal of 2019 IRP portfolios to 2020-21 CAISO TPP	February 2020

Proposed process for 2019 IRP Reference System Portfolio Development

Step #	Activity	Estimated Date
1	Data Development	March-June 2019
2	Informal release: core model inputs + MAG presentation	June 2019
2a	Informal party comment on Step 2 content	July 2019
3	Input validation for RESOLVE & SERVM models	July 2019
4	Develop Calibrated Reference System Portfolio	July-August 2019
5	Informal release of complete RESOLVE model and draft results	September 2019
6	Formal release of Proposed 2019 IRP Reference System Plan	October 2019
7	Workshop on Proposed 2019 IRP Reference System Plan	October 2019
8	Formal party comment on Proposed 2019 Reference System Plan	November 2019
9	Formal release of 2019 Reference System Plan Proposed Decision	December 2019
10	Formal party comment on 2019 Reference System Plan PD	January 2020
11	Commission Decision on 2019 Reference System Plan	February 2020
12	Transmittal of 2019 IRP portfolios to 2020-21 CAISO TPP	February 2020

II. Overview of Reference System Portfolio Development

Iterative Modeling Process



2019 Reference System Portfolio Development

- Creation of 2019 Reference System Portfolio begins with collection of common core inputs for both RESOLVE and SERVM models
- Use of common core inputs (e.g. based on same underlying data) is intended to improve comparison and consistency of model outputs
- RESOLVE and SERVM will be run iteratively with common inputs. Models will be adjusted together until key outputs are sufficiently consistent (e.g. GHG emissions, RPS percentage, curtailment, production costs, etc.)
- CPUC staff requests feedback from parties on the core inputs for RESOLVE and SERVM
  - Baseline conventional, renewables, and storage resources
  - Use of IEPR electric demand peak and energy forecasts, and demand modifiers
  - Electric demand, wind, and solar profiles (in SERVM only)
  - Other smaller model updates such as revised NW hydro modeling and updated burner-tip fuel price forecasts
  - Approaches for modeling transmission capability and upgrades (in RESOLVE only)

Production Cost Modeling Validation of Baseline and Candidate Portfolio

- CPUC system reliability tests (using SERVM) will remain based on the current *Guide to Production Cost Modeling in IRP* with some proposed changes and clarifications of key assumptions:
  - Study year 2030, hourly time steps, zonal model of WECC
  - Simultaneous flow limits between zones will be same as used in last cycle
  - Modeling of BTM PV and BTM storage as "supply"
  - Effective capacity of supply-side wind, solar, and storage resources will be based on Effective Load Carrying Capability (ELCC) values calculated in last year's IRP SERVM work, which includes value provided by storage (to solar)
  - Revised import counting in the Planning Reserve Margin (PRM) assessment (contribution from unspecified imports will be based on contracted out-of-state RA capacity rather than Maximum Import Capabilities)
  - Reference System Portfolio will be validated with an "As-Found" Loss-Of-Load-Expectation (LOLE) study, with Baseline and Candidate portfolio
  - To further assess system reliability, CPUC staff will perform an annual Calibrated LOLE study targeting an annual LOLE result of 0.1 per year

CPUC Staff Will Collaborate with Parties to Improve Modeling Results

- A primary role for production cost modeling in IRP is to validate the system operability and reliability of portfolios developed with capacity expansion modeling such as the RESOLVE model
- CPUC staff's results from RESOLVE and SERVM in the 2017-18 IRP can be improved upon for greater consistency. Use of common core inputs should help considerably. Staff will also work with other parties earlier in the analytical process to improve alignment between different modeling efforts.
  - Earlier sharing of core inputs data should provide greater opportunities for parties to vet and use the same data as CPUC staff
  - Earlier model development (esp. production cost modeling) will increase opportunities for parties to collaborate with staff to bridge differences between modeling efforts

Opportunities for parties to vet core inputs and develop production cost modeling

- CPUC Staff will post the following information to the CPUC website in June:
  - List of baseline conventional, renewable, and storage resources
  - Demand forecast tables containing data related to IEPR and related demand modifying assumptions
  - Hourly profiles for demand and wind/solar resources (for SERVM or other full production cost model)
- The scope of the data release is limited to core inputs sufficient to populate production cost models and the baseline resources in RESOLVE. The data release does NOT contain the full set of data required for RESOLVE (or other capacity expansion models) to produce a candidate resource portfolio incremental to baseline resources. Data not included:
  - Full Inputs & Assumptions document
  - Baseline fixed costs
  - Candidate resource information
- The purpose of providing this data is to allow for parties to provide informal feedback on core 2019-20 IRP modeling assumptions and allow modeling parties to begin developing models in parallel with CPUC staff, with a focus on aligning core production cost model inputs

Key Milestones for Parties: Production Cost Modeling

ACTIVITY	DATE
Obtain baseline resource list, demand forecast, demand/wind/solar profiles, and other core data (Reference System Portfolio Development Step 2)	June 2019
Develop modeling capacity in parallel with CPUC (Steps 3-4)	July-August 2019
Obtain draft set of all modeling inputs and updated Inputs & Assumptions document (Step 5)	September 2019
Perform modeling with RESOLVE, SERVM, or other model to test and validate CPUC's Reference System Portfolio	September-October 2019
Submit modeling results as comments on Proposed 2019 IRP Reference System Plan	November 2019

III. Data Development for Baseline Resources – Conventional, Renewables, and Storage

Baseline Resources Scope

- Baseline resources are those generating units assumed to be fixed as a capacity expansion model input, whereas candidate resources are selected by the capacity expansion simulation and are incremental to the baseline.
- Baseline resources are all existing and online resources, plus LSE-owned or contracted resources that are still under development, consistent with the definition used in the 2017-18 IRP cycle. Projects without approved contracts are not considered part of the baseline.
- Specific mandated resource procurement is also considered baseline, e.g. achievement of the AB 2514 storage target

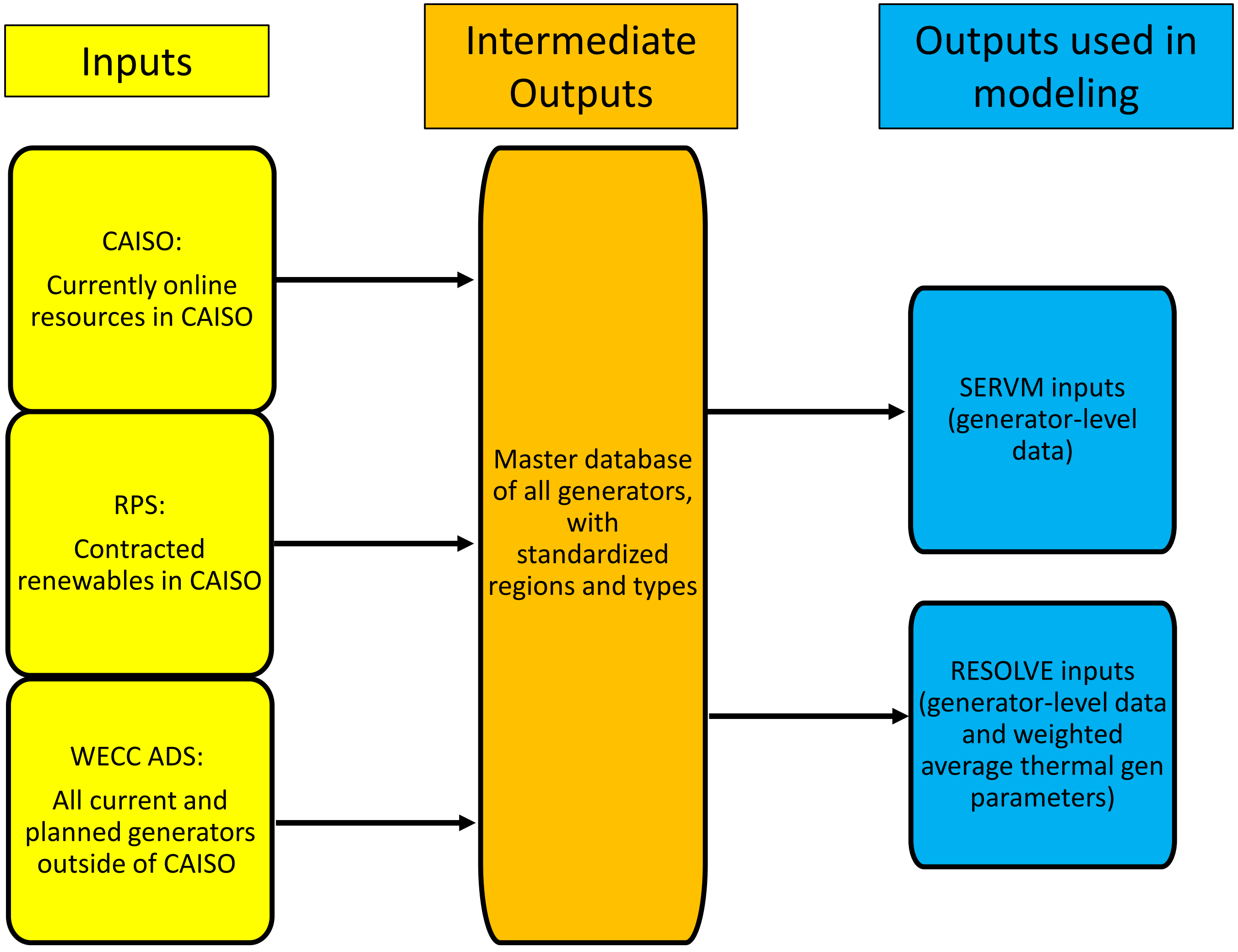
Retirements, Repowering, Risk Adjustments

- Retirements
  - Power plants with announced retirements are modeled as retired. Compliance with Once-Thru-Cooled Water Board policy is assumed and Diablo Canyon Power Plant is retired in 2024/2025.
  - RESOLVE will include new economic retention functionality to examine what portion of the existing gas-fired generation fleet may need to be retained or allowed to retire within the IRP planning horizon
- Repowering
  - Staff is aware that a significant fraction of California's wind capacity may need to be repowered by 2030
  - Further data gathering and RESOLVE development will be needed to explicitly consider repowering. Some considerations:
    - Useful life assumption - use a standard assumption across all resources in a technology category
    - Repowering capital and operating costs - assume same as greenfield costs
    - Nameplate capacity - assume same as existing project
- Risk Adjustment for LSE-owned or contracted resources not yet online
  - Staff will update this assumption from the 16% used in 2017-18 IRP cycle, and prior to that in the RPS Calculator, to be a 5% adjustment to installed capacity to allow for projects under development failing to come online
  - This considers parties' comments and average failure rates forecast by LSEs in their most recent RPS Procurement Plans

Creating Master WECC-wide Generator List

- Aligning generator data in SERVM and RESOLVE is crucial for comparing both models' cost, reliability, and emissions results.
- To ensure alignment, CPUC staff developed a suite of Python programs to automatically generate inputs for both SERVM and RESOLVE from a common set of data sources.
  - These programs take raw data from the CAISO, the WECC ADS (Anchor Data Set), and the CPUC RPS database.
  - They clean, standardize, and combine these datasets into a complete "master" list of baseline generators.
  - They then use the master list to calculate operational inputs needed for both models (heat rates, ramp rates, startup fuel/cost/time).
  - Where possible, the programs favor the use of CAISO data over WECC ADS data, as it is more granular (especially for generator start information and heat rates).
- A public dataset showing the list of generators and relevant information about in-service dates, regions, and types will be posted to the CPUC website, allowing for crosswalks between the two models.

Creating Master WECC-wide Generator List: Process Diagram



- Boxes represent datasets, arrows represent Python scripts that process the data
- Taken together, the yellow boxes represent the complete set of current and planned resources in the WECC
- Intermediate "master database" output will be posted (redacting confidential portions)

WECC Installed Capacity by Resource Type and RESOLVE Zone in 2030, MW

	BANC	CAISO	IID	LDWP	NW	SW	Other WECC [5]	**TOTAL**
Biogas [1]	0	272	0	0	0	0	0	**272**
Biomass	18	576	77	0	630	113	1,211	**2,625**
Combined Cycle	1,863	15,076	255	2,755	9,573	19,741	10,194	**59,457**
Cogen [2]	0	2,237	0	0	0	0	3,487	**6,941**
Coal	0	0	0	0	7,364	6,266	8,420	**22,049**
Geothermal	0	1,613	792	0	142	704	677	**3,928**
Hydro	2,765	7,244	84	290	34,378	2,680	21,572	**69,013**
Nuclear	0	635	0	407	1,757	3,000	0	**6,329**
Peaker [2]	867	8,030	327	1,647	2,993	6,808	7,208	**27,880**
Pumped Hydro [3] [6]	0	1,858	0	1,460	500	220	543	**4,580**
Reciprocating Engine [2]	0	255	0	0	0	0	287	**542**
Solar [4]	146	11,389	119	948	2,661	1,936	1,140	**18,338**
Steam [2]	0	0	0	371	0	1,202	3,098	**4,671**
Wind	0	5,564	0	725	12,488	2,127	7,501	**28,405**
TOTAL	**5,659**	**55,966**	**1,654**	**8,602**	**72,485**	**45,326**	**65,338**	**255,031**

Notes:

[1] Biogas is grouped with biomass for non-CAISO areas to reduce model complexity.

[2] Certain non-CAISO area gas generator types are grouped with Peaker types to reduce complexity (see next slide).

[3] This table does not include baseline battery storage. See the end of this section for details on baseline battery storage assumptions.

[4] BTM solar PV is not represented in the table above and will be presented in the demand-side inputs section.

[5] "Other WECC" refers to areas that are within WECC but are not represented in RESOLVE, such as Alberta, British Columbia, and Colorado (however, RESOLVE does represent specified hydro from BC since significant amounts go to CAISO entities). SERVM does model these areas explicitly.

[6] RESOLVE does not model pumped hydro in non-CAISO areas to reduce model complexity.

Non-CAISO Thermal Capacity Modeled in RESOLVE as Peaker, in 2030, MW

- To reduce RESOLVE model complexity and runtime, the number of natural gas generator classes outside of CAISO is reduced by aggregating different power plants together into one "Peaker" resource
- Non-CAISO RESOLVE zones contain a total of 1,233 MW of Cogen, Steam, and Reciprocating Engines. Staff moved these resources to the Peaker class. These reclassifications were reflected in the summary table on the previous slide.

	MW
NW_Reciprocating_Engine	391
SW_Reciprocating_Engine	323
NW_ST	272
IID_ST	145
NW_CHP	53
BANC_Reciprocating_Engine	49
Total MW moved to Peaker	**1,233**

Variable Operations and Maintenance (VOM) Costs

- CPUC staff refreshed the VOM costs used from the last cycle of IRP.
- CAISO defines VOM as “variable non-fuel costs that may include raw water, water and wastewater disposal expenses, chemicals and other consumable materials and supplies.”
- The chief data source for VOM was a December 2018 Nexant report available here:
  - http://www.caiso.com/Documents/VariableOperationsandMaintenanceCostReport-Dec212018.pdf
- CPUC staff took values from this report and assigned them to generators.
  - Staff assumed that combined cycle and peaker plants had Selective Catalytic Reduction for NOx reduction, which tends to raise their VOM costs relative to a no-SCR case
  - Per the data in the Nexant report, staff used the age of the plant as a factor in assigning VOM costs

Detailed Scope of Modeled VOM Costs

<u>INCLUDED – Costs associated with consumables and waste disposal, such as:</u>

- Raw water
- Waste and wastewater disposal expenses
- Chemicals, catalysts and gases
- Ammonia for selective catalytic reduction
- Lubricants whose use depends upon energy production
- Consumable materials and supplies

<u>EXCLUDED – Major maintenance (MM) costs and other maintenance (OM) Costs, such as:</u>

- Scheduled major overhaul expenses for maintaining prime mover
- Major maintenance labor expenses
- Major maintenance spare parts costs
- Balance-of-Plant (BOP) major maintenance costs that cannot be done with routine maintenance or while in commercial operation
- Maintenance of equipment such as water circuits, feed pumps, main steam piping, and demineralizer systems
- Maintenance of electric plant equipment, which includes service water, DCS, condensate system, air filters, and plant electrical
- Maintenance of miscellaneous plant equipment such as communication equipment, instrument and service air, and water supply system

Summary of VOM Cost by Baseline Resource Type

	2016 $/MWh
Coal	2.48
Nuclear	1.80
Biomass	1.55
Peaker	1.32
Geothermal	1.09
Reciprocating Engine	1.03
Cogen	0.77
Steam	0.30
Combined Cycle	0.25

- Solar, wind, and battery resources are modeled with zero VOM cost because maintenance costs are included in capital and fixed costs for these resources.
- Data above is a summary of a larger table; the VOM cost used in SERVM and RESOLVE varies by region and resource type. A full table with all RESOLVE resource types will be posted in the June data release.
- CPUC staff is currently developing VOM costs for “candidate” Peakers and Combined Cycles

Pmin and Ramp Rate Data Issues

- Combined Cycle (CC) generators are typically composed of multiple subunits: one steam turbine (ST) and one or more Combustion Turbines (CT)
  - Each subunit has a level of minimum output in MW (Pmin), and the combined operation of subunits may create additional constraints that can impact the overall Pmin of the CC
  - The Pmin of the entire CC can be reported either in terms of "1x1" (operating the CC with only one CT and one ST) or a larger "Nx1" (operating the CC with all subunits committed, including all N subunit CTs)
- CAISO datasets report generator Pmins as 1x1
- However, WECC datasets report generator Pmins as Nx1
- In the technology table shown previously, CPUC staff calculated estimates for WECC 1x1 Pmins to be consistent with CAISO Pmins
  - To estimate WECC 1x1 Pmins, staff multiplied WECC Nx1 Pmins by the ratio of (capacity-weighted average of CAISO Pmin as percentage of Pmax) / (capacity-weighted average of WECC Pmin as percentage of Pmax), approximately 60%
- The RESOLVE and SERVM models represent CC generators as one, aggregated unit instead of individual ST and CT units
- There is therefore a need to:
  - 1) Decide whether CC Pmins' should be modeled using the 1x1 configuration or the Nx1 configuration
  - 2) Once that is decided, standardize the CAISO and WECC datasets to both report Pmins with the chosen configuration. Use this data to model CCs.

Pmin and Ramp Rate Data Issues, cont.

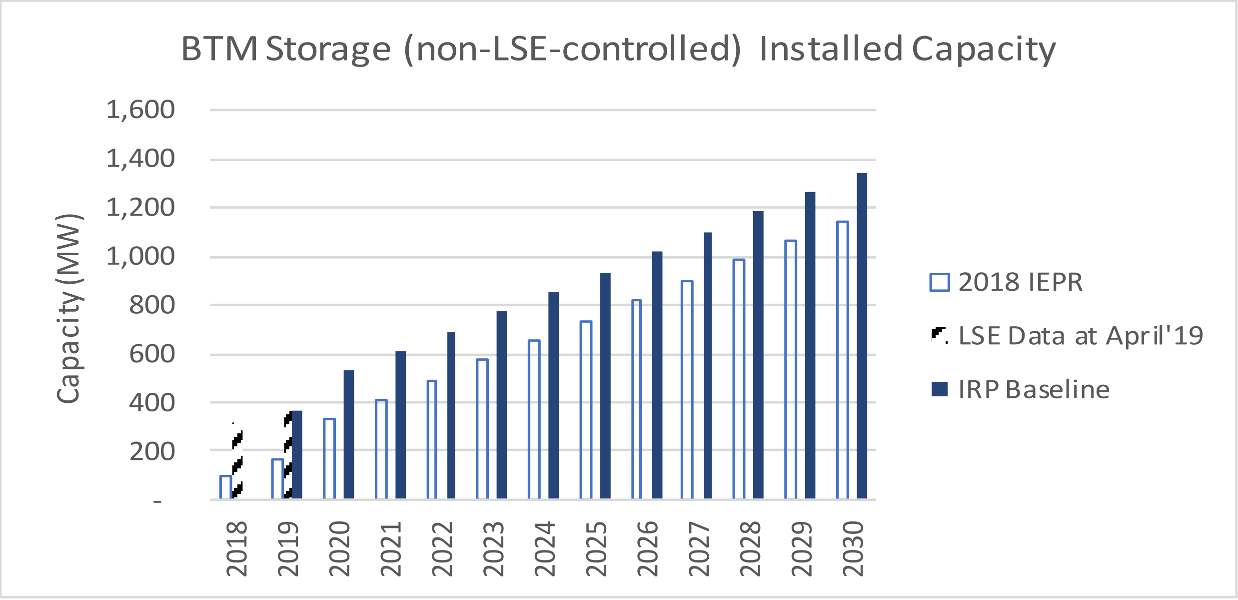
- How should the minimum power level (Pmin) of aggregated CC units be represented?
  - Should IRP modeling assume that CC units have a Pmin corresponding to one CT plus one ST (1x1 mode)?
  - Or, should IRP modeling assume that CC units have a Pmin corresponding to the minimum power output when all N CT subunits are online at their respective Pmin levels?
- How should the ramp rate over the operational range of the aggregated CC unit (from Pmin to Pmax) be represented in a way that is consistent with the suggested 1x1 or Nx1 Pmin representation?
  - In the underlying data, ramp rates are generally only reported by subunit, and do not account for switching between modes (i.e. committing and ramping up CT subunits), which takes time. Thus using ramp rates as-is will overstate the ramp rate of the whole unit.
  - How should this be accounted for?
  - What is a reasonable assumption for transition time between modes?

Baseline battery storage developed from multiple sources

- Sources to inform baseline storage resource capacity and assumptions:
  - AB 2514 storage mandate which specifies MW requirements by IOU, by interconnection domain; online by 2024
  - CEC's IEPR demand forecast contains some BTM storage (trend analysis of SGIP and CEC 1304 Power Plant data) to represent installs incremental to the AB 2514 storage mandate
  - LSEs' responses to CPUC Staff Data Request: contracted, owned and/or online as of April 2019
    - BTM online, independent of LSEs; and
    - LSE-controlled, including BTM
    - Duration observed to be mostly 4 hours for LSE-controlled resources
    - For non-LSE-controlled BTM resources, duration was typically about 2 hours

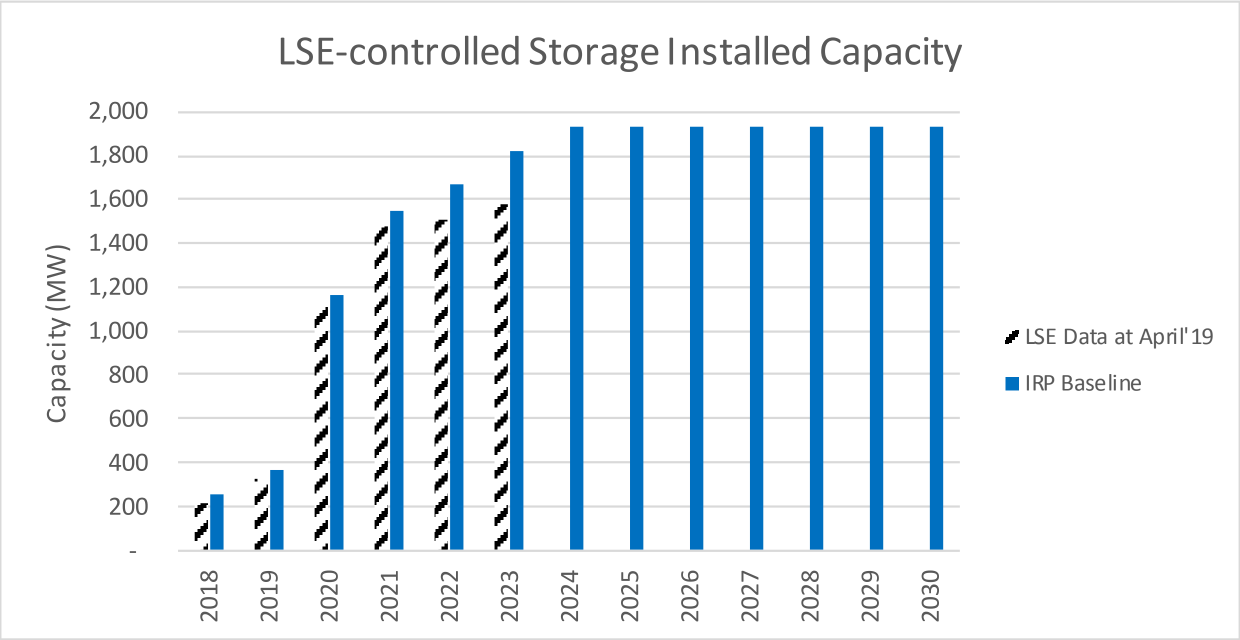
BTM battery storage is modeled as a resource with installed capacity

- Avoid double-counting IEPR by backing out Peak Load Impact of BTM storage in load forecast for RESOLVE and SERVM
- Approx. 374MW installed BTM (non-LSE-controlled) as of April 2019, indicating
  - current SGIP-driven installed capacity exceeds IEPR forecast for 2019
  - significant non-SGIP and non-AB 2514 capacity has been installed
- Propose adding about 200MW to IEPR Installed Capacity forecast to form baseline for new IRP resource type: BTM (non-LSE-controlled)



Reconciling LSE-driven battery storage procurement and AB 2514 mandate

- Assume achievement of AB 2514 mandate (1,325 MW by 2024) plus incremental IOU, CCA and ESP procurement
  - Accelerated and/or additional IOU-contracted/owned capacity evident in April 2019 data, when considering required amounts by interconnection domain
  - CCAs and ESPs have contracted approx. 110MW as of April 2019



IV. Use of IEPR Electric Demand and Demand Modifier Datasets, plus Other Key Inputs

Demand forecast is a core modeling input

- Electric demand forecast is a core input to any electric system planning analysis
  - Per the Single Forecast Set agreement,* IRP will be using the Energy Commission's 2018 Integrated Energy Policy Report (IEPR) Update Forecast as a core input
- Any planning exercise must also consider uncertainty. CPUC's IRP planning models consider uncertainty by studying:
  - A range of future weather scenarios through stochastic production cost modeling (SERVM)
  - A range of future electric system resource portfolios, electric demand, and policies through scenarios/sensitivities in capacity expansion modeling (RESOLVE)
- IEPR forecast must be translated into the range of inputs needed by CPUC's IRP planning models

* See: Final 2018 Integrated Energy Policy Report Update, Volume II- Clean Version

Electric demand modifiers are modeled as individual resources

- RESOLVE and SERVM both model certain demand modifiers (aka demand-side resources/programs) as individual resources
  - More flexible and accurate to explicitly model effects of BTM PV, EE programs, TOU rates, etc. rather than leaving their effects embedded with electric demand
- When demand modifiers are backed out of the demand forecast and instead modeled as supply-side resources, some adjustments are required:
  - Adjusting for transmission and distribution (T&D) losses
  - Avoid carrying reserves for the modeled demand increase due to backing out a demand modifier
    - Planning Reserve Margin (PRM)
    - Hourly operating reserve requirements

Decomposition of IEPR demand forecast

- To individually model demand modifiers, the IEPR demand forecast must be decomposed into constituent parts in terms of annual energy, peak impact including any shifting effect, and hourly profiles
  - Multiple IEPR work products are required to conduct the analysis, including:
    - Load Serving Entity and Balancing Area forecast tables
    - Load modifier breakout tables for the 3 large IOU areas
    - Hourly profiles for the CAISO planning areas
- In the RESOLVE and SERVM models:
  - Additional Achievable Energy Efficiency (AAEE), Time-Of-Use (TOU) rate effects, and Light-Duty Electric Vehicle (LDEV) load are each modeled individually with fixed hourly profiles
  - BTM PV (baseline committed + Additional Achievable PV) and BTM storage are modeled as resources with installed capacity
  - Other demand modifier components in the IEPR are left embedded in demand (Other Electrification, Climate Change, BTM CHP, Load-Modifying Demand Response (LMDR))

Using the IEPR to develop a range of RESOLVE scenarios

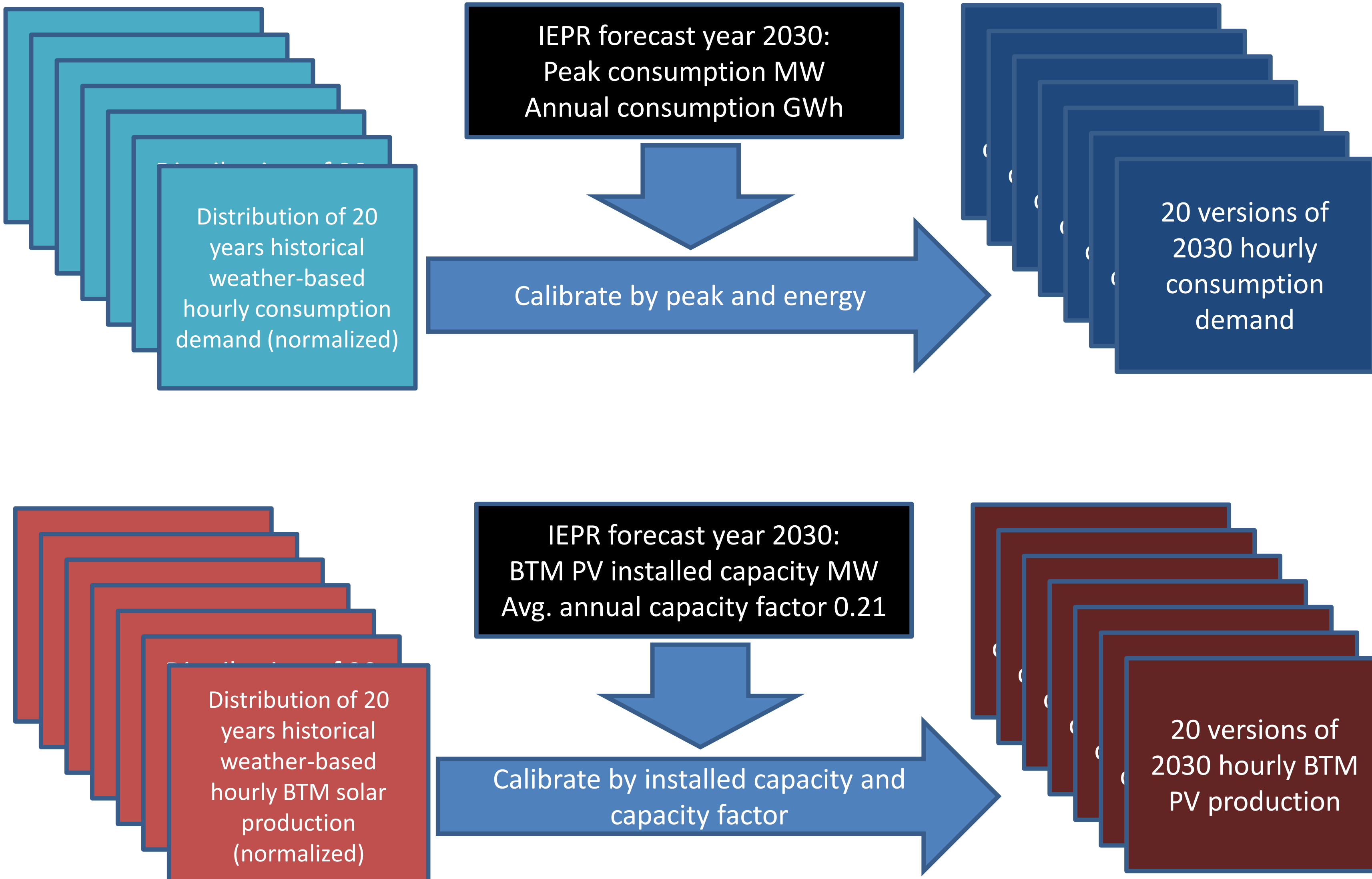
- RESOLVE's core demand forecast starts with the IEPR's Single Forecast Set
- The IEPR includes low, mid, and high cases which can be combined into a range of different scenarios that RESOLVE can study

Electric demand component	IEPR cases included in RESOLVE		
Baseline consumption		Mid	High
Light-duty electric vehicles	Low	Mid	High
Committed BTM PV	Low	Mid	High
Additional Achievable PV	High-Low	Mid-Mid	Low-High
Time-Of-Use rate effects		Mid	
Additional Achievable EE	High-Low	Mid-Mid	Low-High

Using the IEPR to calibrate SERVM's hourly profiles

- SERVM uses a historical weather-based distribution of hourly profiles in order to consider a range of future weather conditions
- IEPR demand and demand modifier data are used to build up the hourly profiles used in SERVM
  - Annual peak and energy consumption are calculated from the IEPR data and used to calibrate SERVM's historical weather-based distribution of hourly demand profiles. SERVM does not directly use the single average hourly demand profile included with the IEPR.
  - BTM PV installed capacity from the IEPR is used to calibrate SERVM's weather-based hourly solar profiles
  - Other demand modifiers are assumed weather independent and SERVM uses the IEPR hourly profiles for these modifiers directly
- The following section will detail the methods used to develop SERVM's historical weather-based distribution of hourly profiles

Using the IEPR to calibrate SERVM's hourly profiles



Using the IEPR to scale RESOLVE's hourly profiles

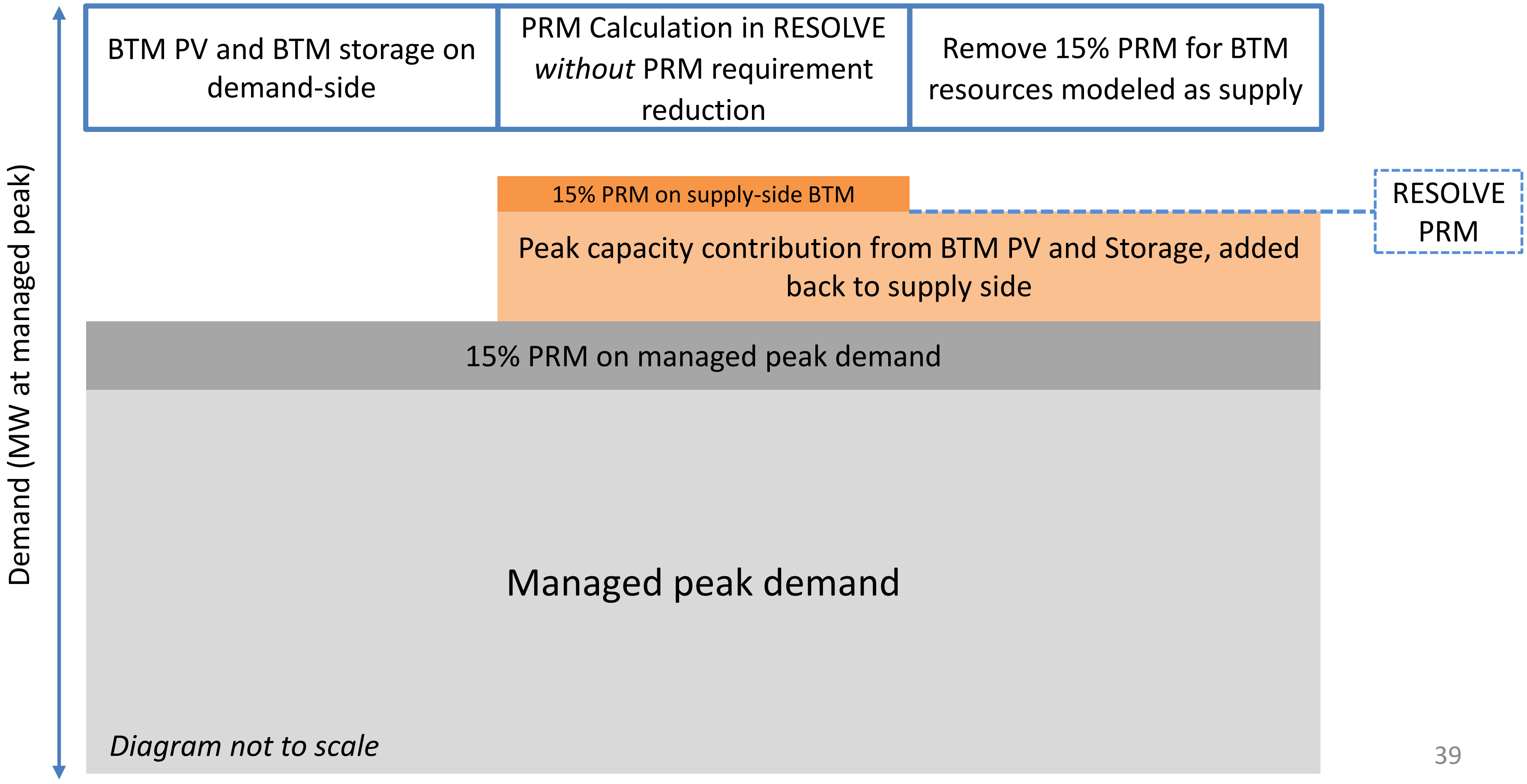
- RESOLVE includes an hourly dispatch module and represents annual operations with 37 weighted representative days
- CPUC staff will be using this same methodology for this IRP cycle
- IEPR demand and demand modifier data are used to build up the hourly profiles of the 37 representative days
  - Demand profiles for RESOLVE's 37 representative days are scaled to meet IEPR annual energy values for both baseline consumption and load modifiers
  - BTM PV installed capacity is used to scale up RESOLVE's 37 day-hourly solar profiles

Using the IEPR in RESOLVE's PRM Constraint

- RESOLVE models peak demand conditions separately from its hourly dispatch module via the Planning Reserve Margin (PRM) constraint
- The PRM constraint ensures that effective capacity of all resources including imports is 15% above the 1-in-2 managed peak demand
- BTM resources reduce the capacity needed to satisfy the PRM. When modeling BTM resources on the supply-side and removing their peak reduction effect from electric demand, we want to avoid imposing a PRM on this demand increase.
- To account for this in RESOLVE, the PRM requirement is reduced by 15% of the MW of peak reduction from the BTM resources modeled on the supply-side in RESOLVE

Illustrative adjustment to RESOLVE's PRM constraint from modeling BTM resources as supply

- BTM PV and BTM storage contribute to RESOLVE's PRM constraint as supply-side resources
- To be consistent with Resource Adequacy accounting, an adjustment is necessary



Summary of SERVM CAISO area demand forecast inputs

Planning Area	PG&E		SCE		SDG&E	
Electric Demand Component [1]	2020	2030	2020	2030	2020	2030
Consumption, MW peak	22,838	25,760	25,353	28,753	4,825	5,517
Consumption, GWh load	111,274	123,640	110,047	123,337	22,123	24,691
Light-duty electric vehicles, GWh load	2,528	7,531	1,851	5,398	562	1,662
Time of use rate effects, GWh load [2]	-	23	-	13	0.03	2
Additional Achievable EE, GWh savings	2,939	12,949	2,881	14,108	572	3,029
Committed BTM PV installed cap MW	5,493	10,269	3,476	7,292	1,504	2,458
Additional Achievable PV installed cap MW	63	720	67	740	14	168
BTM storage installed cap MW [3]	122	469	167	566	65	198

[1] All values are at the system level (includes gross up for losses)
[2] TOU effects have a tiny increase in annual energy while decreasing hourly demand during peak hours
[3] BTM storage capacity represents the amount reported from the IEPR. Reconciling with responses from a recent CPUC data request to LSEs will moderately elevate this projection.

Other IEPR or related inputs necessary for modeling

- Both RESOLVE and SERVM will also use the following as core model inputs:
  - For outside California loads, use electric demand forecasts from the WECC's Anchor Data Set 2028 Phase 2 V1.2
  - For CARB cap and trade GHG allowance price projections, use the CEC's 2019 IEPR Preliminary projection here: https://efiling.energy.ca.gov/GetDocument.aspx?tn=227328&DocumentContentId=58424
  - For natural gas burner tip price forecasts, use the CEC's 2019 IEPR Preliminary model found here: https://www.energy.ca.gov/2014publications/CEC-200-2014-008/April_2019_Model_CEC-200-2014-008.xlsm

V. Development of Hourly Wind and Solar Profiles in SERVM

Purpose Of Presentation

- Stochastic Production Cost Models (PCMs) are used to forecast electric grid behavior
  - Model used by CPUC is hourly for entire western US
  - ***20 years of hourly historical weather data is used to create synthetic load, wind and solar profiles***
- This Presentation describes development of solar and wind profiles for CPUC Stochastic PCM (using SERVM)

Machine Learning

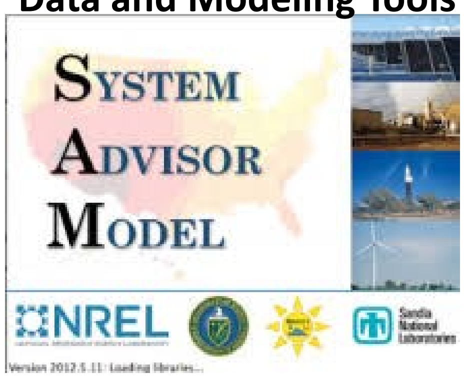
- Mathematical model based on set of training data
- Used to develop forecasts without being explicitly programmed
- ***Our approach uses machine learning to train solar and wind models***
  – 20 years of historical weather data is then used to create synthetic solar and wind profiles
  – Synthetic profiles are the basis of stochastic PCM

Training Data

- Confidential hourly (CAISO) historical production data (MWh)
  - Over 300 resource-years of data
  - 2014 – 2017
- Hourly historical weather data across western US
  - 1998 – 2017

- ***Solar NSRDB***
  - ***1998 – 2017***
- ***Wind Toolkit***
  - ***2008 – 2013***

Data and Modeling Tools

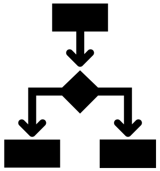


NATIONAL CLIMATIC DATA CENTER
Revealing the Past, Protecting the Future
NCDC
NATIONAL OCEANIC & ATMOSPHERIC ADMINISTRATION

- *Worldwide*
  - *>20k stations*
- *1940 - current*

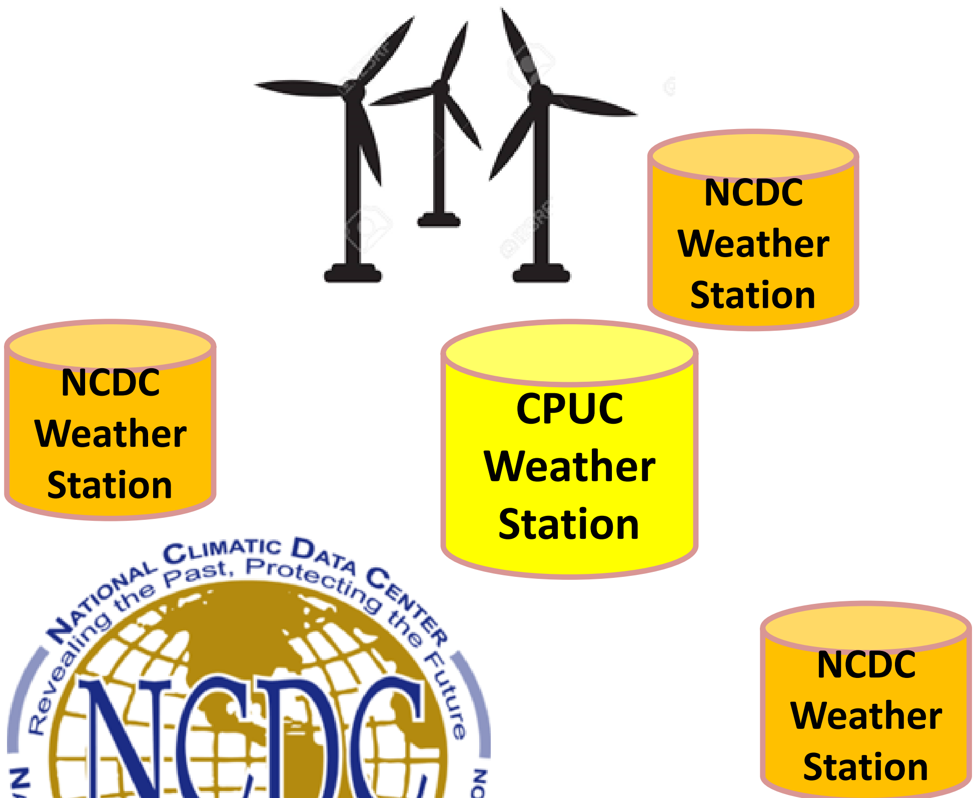
Solar **Wind + (Temp, Dewpoint, …)**

Mathematical Model



- For each resource-year in our dataset:
  - Regress solar or wind weather data to productio using appropriate model:
    - Solar (irradiance): PVWatts
    - Wind (windspeed): Bespoke model based NCDC win dataset
  - This produces a series of local best fits
- For solar and wind:
  - Take median of local best fit parameters to create global best fit parameters

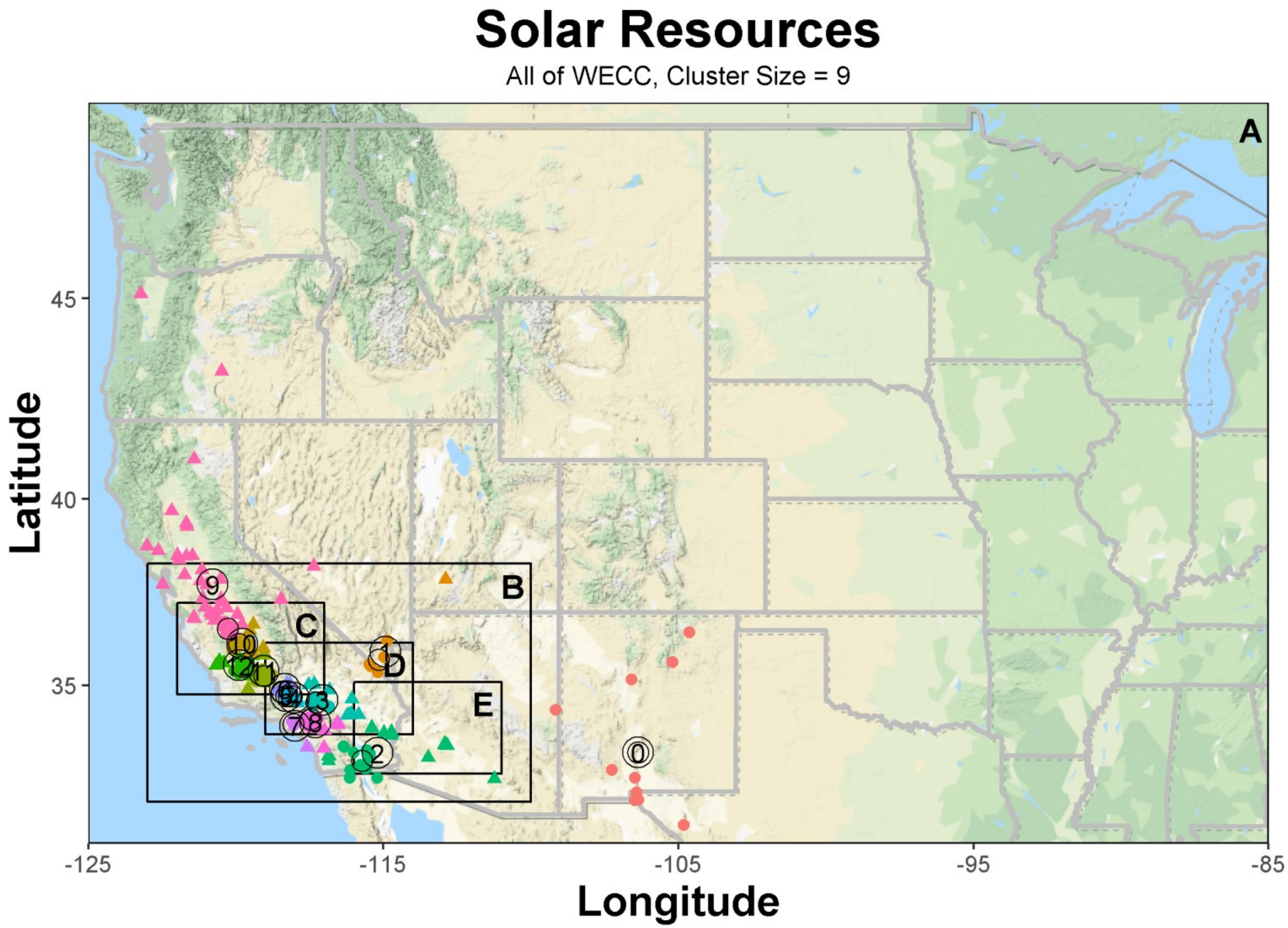
Weather Stations for Wind Model



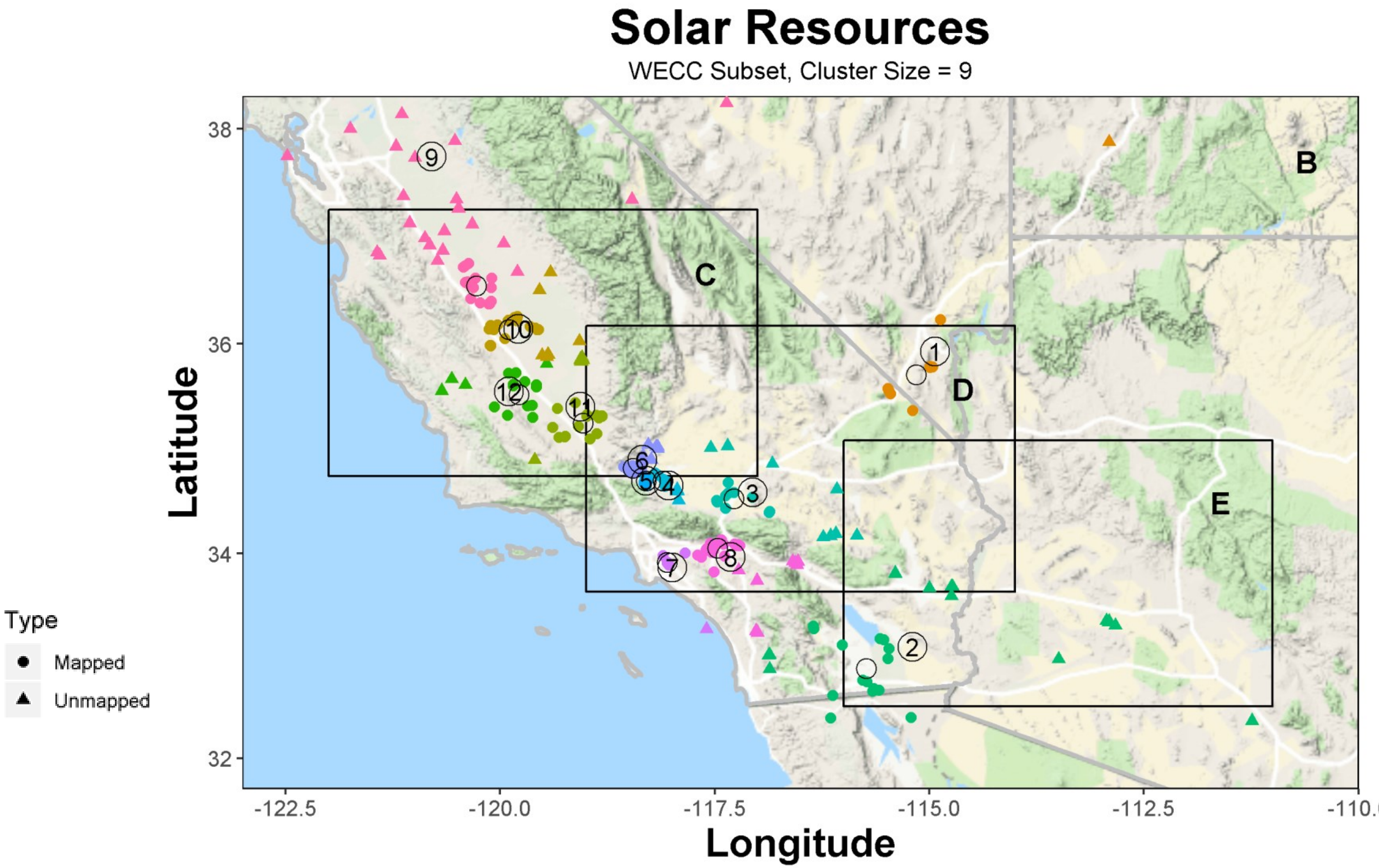
- Choose closest NCDC weather stations to our resources
- Use all data from nearest and aggregate missing data from next nearest until nearly full
- Supplement few remaining missing by linear interpolation

Types of Weather Stations

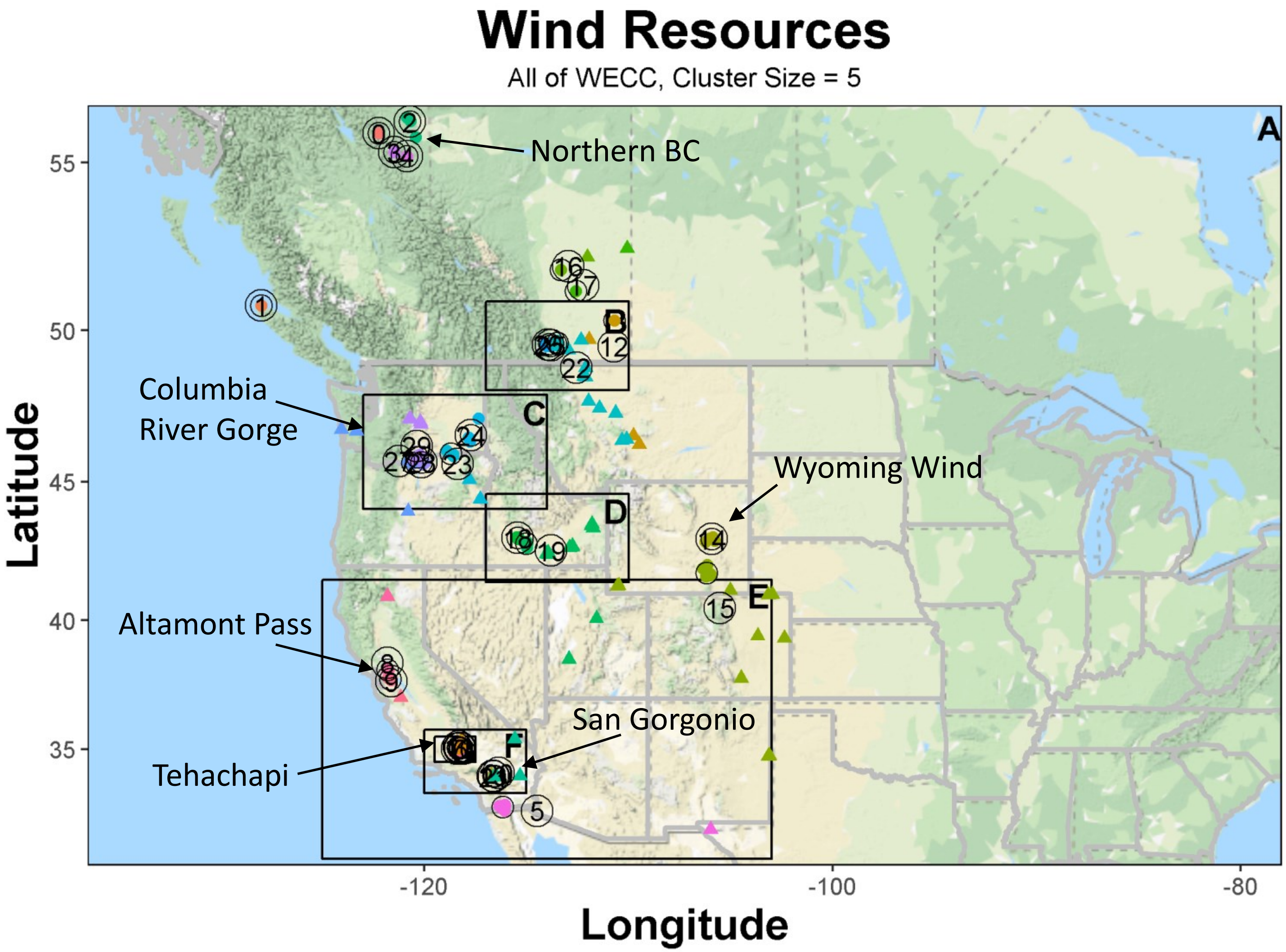
- ***Where should we locate our weather stations?***
- **Wind**: Aggregated NCDC weather stations close to wind resources
- **Wind and Solar**: Need smart locations to store synthetic profiles
  - Synthetic profiles define scenarios simulated by the Stochastic PCM
  - Not practical to store synthetic profiles at location of each resource in the model
  - Instead pick cluster centroids



- Each point represents a single solar resource in the model



- Clusters are color coded
- Each open circle / number represents a cluster centroid


Wind Resources
All of WECC, Cluster Size = 5
Northern BC
Columbia
River Gorge
Wyoming Wind
Altamont Pass
San Gorgonio
Tehachapi
A
B
C
D
E
F
Latitude
Longitude
55
50
45
40
35
-120
-100
-80

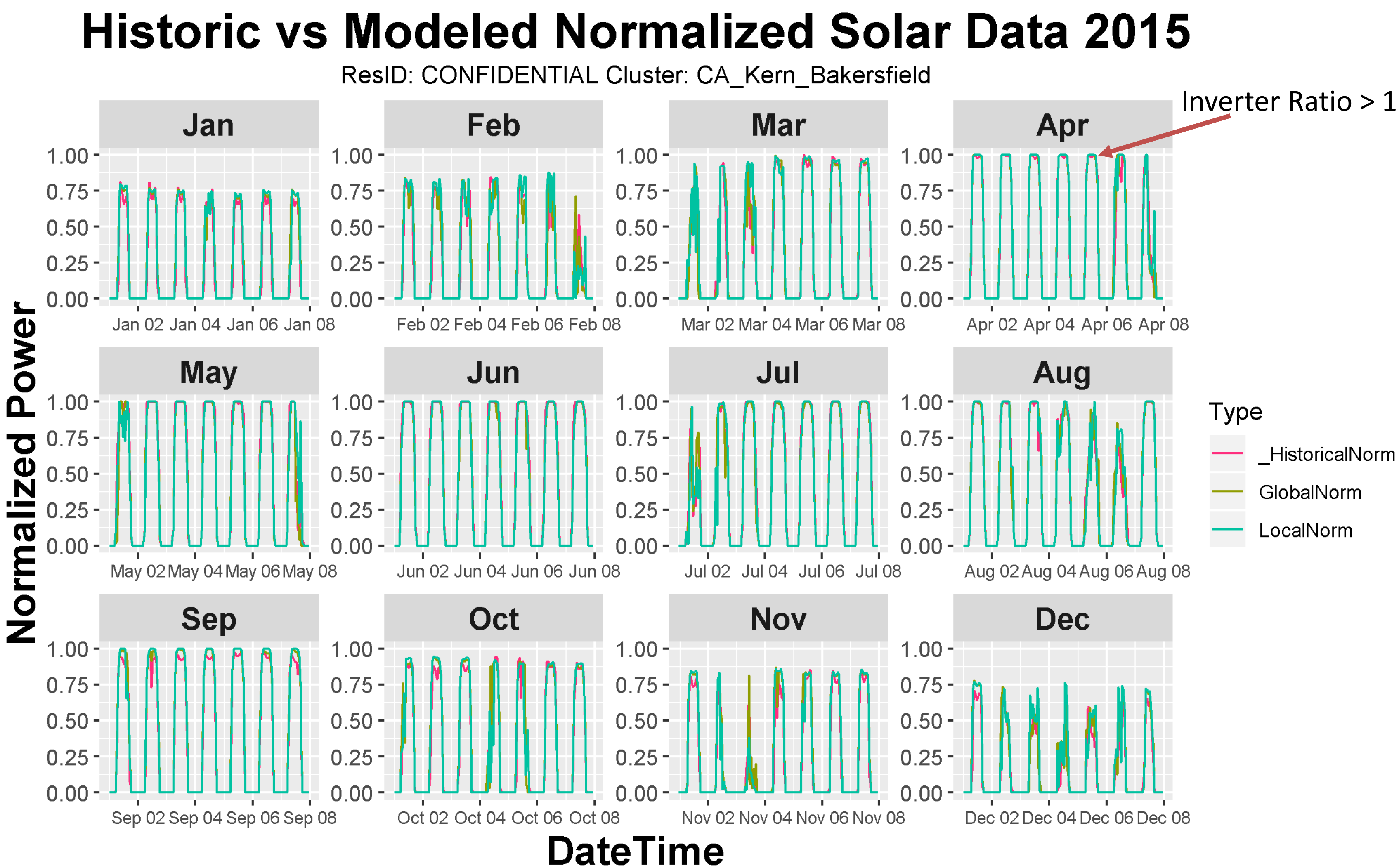
Clustering Algorithm

- This approach increases longitudinal resolution of solar data
  - Doubles number of weather stations in CA
- Hierarchical clustering algorithm used to automate selection of weather stations
  - Hdbscan / python
  - Primarily chosen because it works with geospatial data

Solar Model

NREL
PVWatts® Calculator

- Sunlight propagates at the speed of light
- Cloud cover can be measured by satellite
- Accurate models exist for power production from PV panels
  - NREL / PVWatts
- Model accounts for
  - Array type (fixed v tracking)
  - Inverter ratios

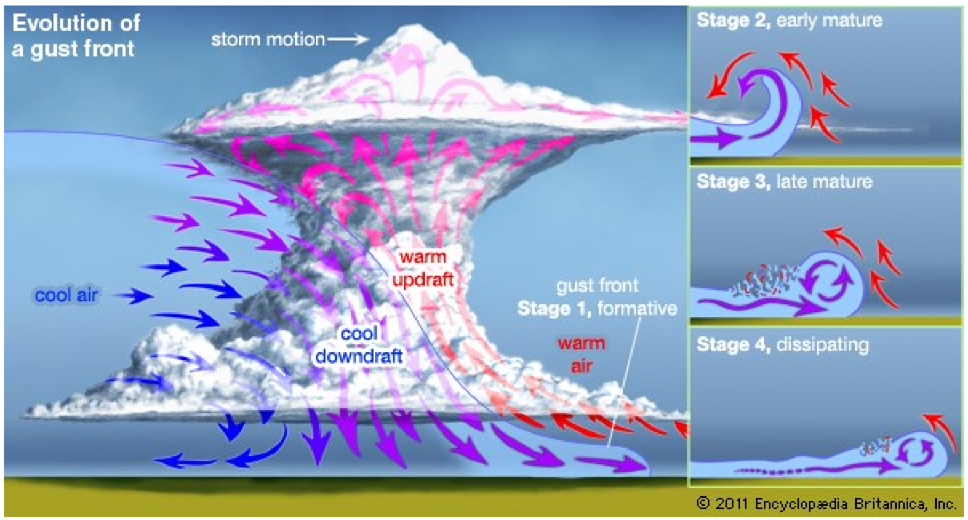


- First week of each month in year displayed for a single resource

Solar Model Summary

- Global best fit trained from over 160 resource-years
- Excellent fits
  - $R^2 > 90\%$
- Increased longitude resolution

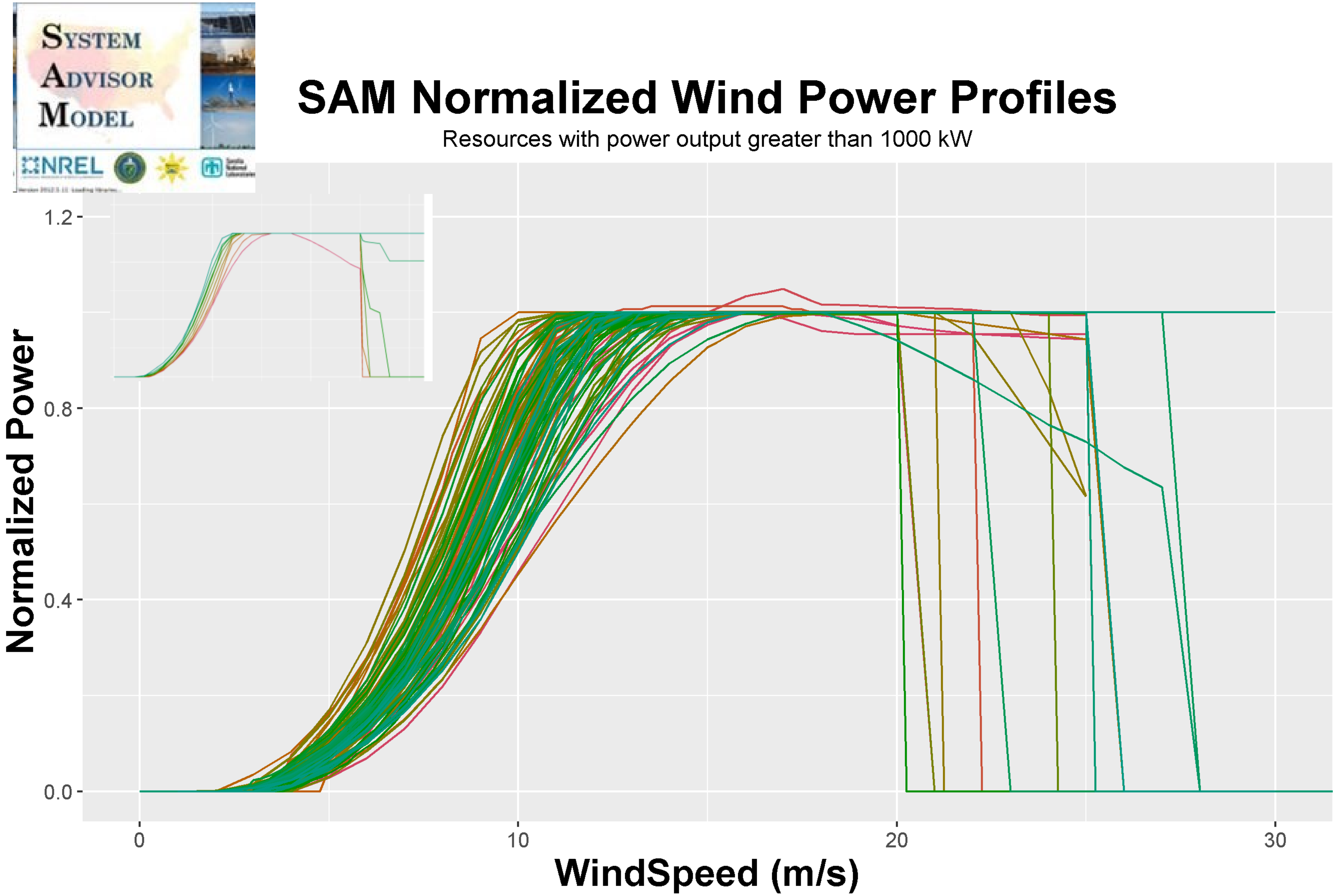
Wind Model



- Propagation of wind systems is complex and highly dependent on topology
- Models exist for power production from wind farms but require accurate and highly local wind speed data
- NREL SAM model cannot be used since existing wind data does not cover appropriate years
- **We have developed a novel wind model based on National Climatic Data Center windspeed data**

SAM Normalized Wind Power Profiles

Resources with power output greater than 1000 kW

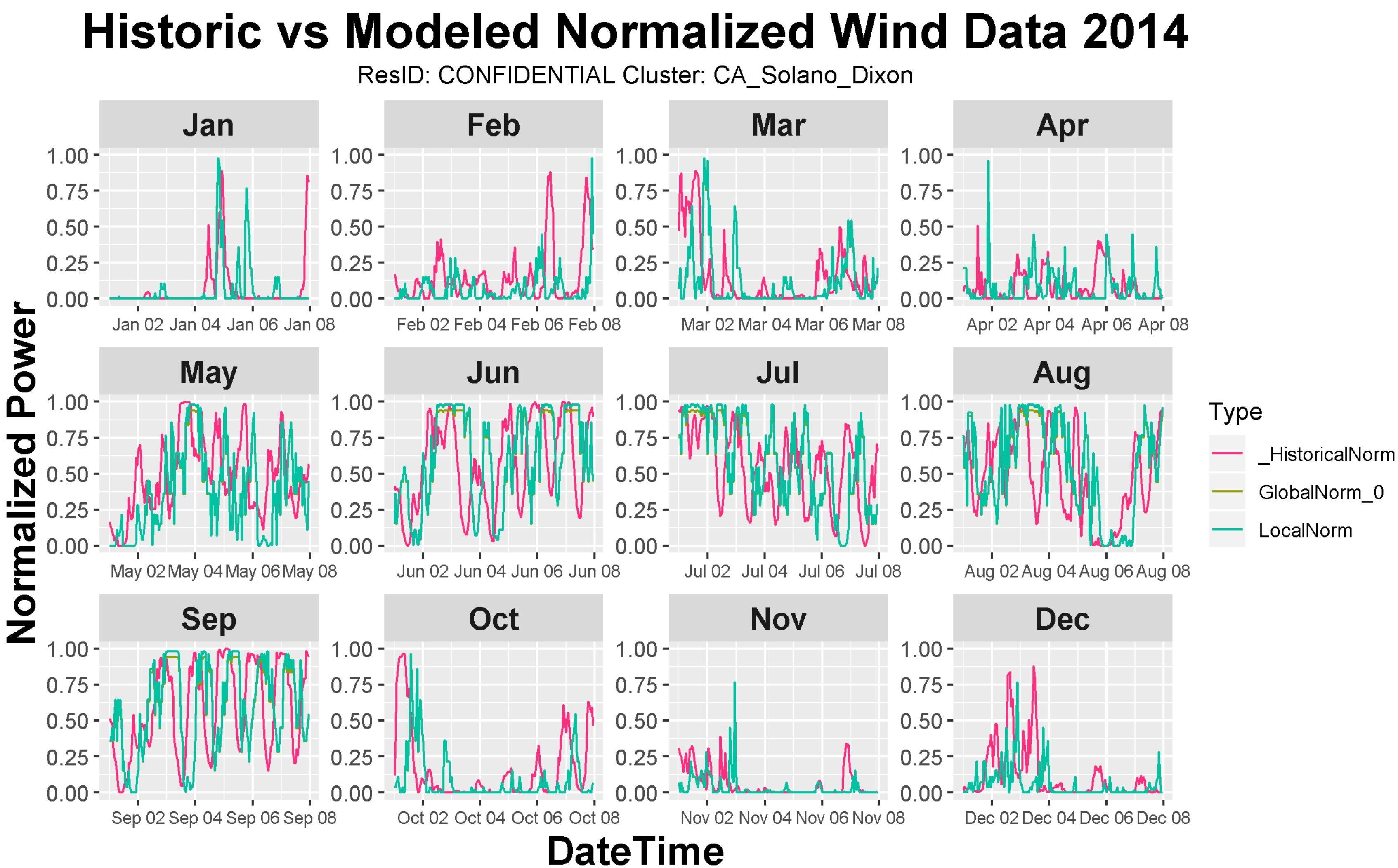


- Each line is a different wind turbine type contained in NREL SAM database
- Inlay represents quantiles of this distribution

CPUC Wind Model

- Based on
  - SAM wind turbine production curve database
    - Power versus windspeed for most commercial turbines
  - NCDC wind speed database
    - CPUC wind weather stations
      - Aggregated NCDC weather stations to account for missing data
- CPUC model chosen for simplicity
  - Optimization constrains Load Factor
  - Only two multiplicative factors:

$$\text{Production (MW)} = a * F(b * v)$$

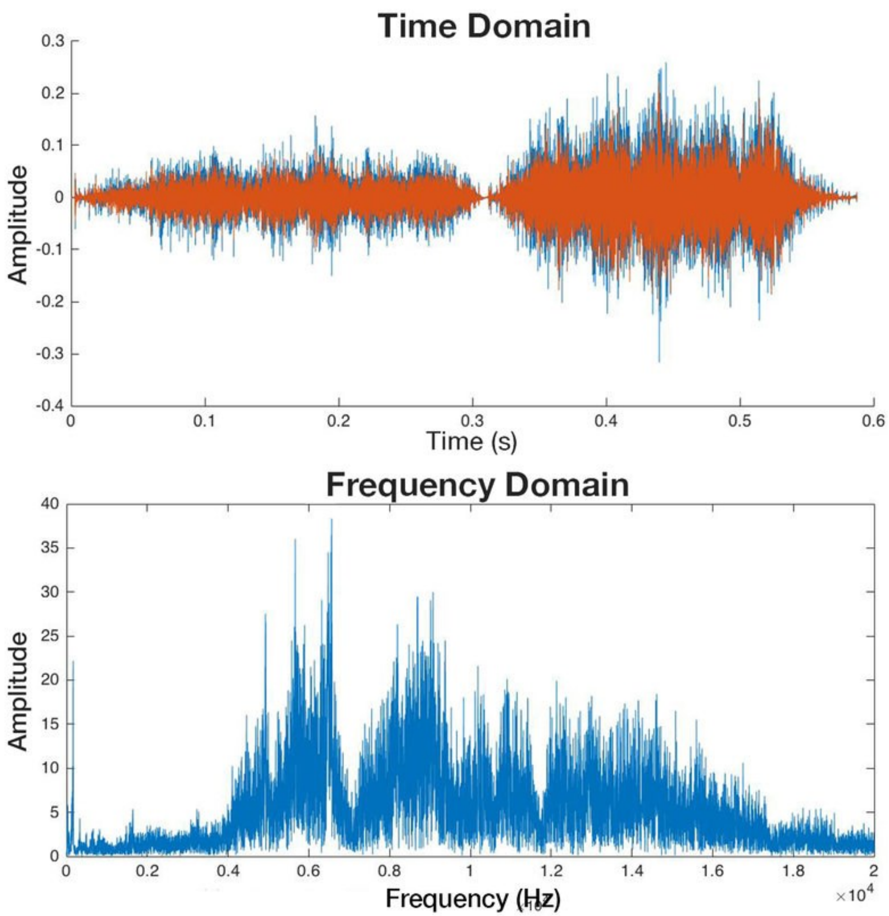

Historic vs Modeled Normalized Wind Data 2014
ResID: CONFIDENTIAL Cluster: CA_Solano_Dixon
Jan
Feb
Mar
Apr
May
Jun
Jul
Aug
Sep
Oct
Nov
Dec
Normalized Power
DateTime
1.00
0.75
0.50
0.25
0.00
Jan 02 Jan 04 Jan 06 Jan 08
Feb 02 Feb 04 Feb 06 Feb 08
Mar 02 Mar 04 Mar 06 Mar 08
Apr 02 Apr 04 Apr 06 Apr 08
May 02 May 04 May 06 May 08
Jun 02 Jun 04 Jun 06 Jun 08
Jul 02 Jul 04 Jul 06 Jul 08
Aug 02 Aug 04 Aug 06 Aug 08
Sep 02 Sep 04 Sep 06 Sep 08
Oct 02 Oct 04 Oct 06 Oct 08
Nov 02 Nov 04 Nov 06 Nov 08
Dec 02 Dec 04 Dec 06 Dec 08
Type
_HistoricalNorm
GlobalNorm_0
LocalNorm

Wind Model

- There are over 140 resource-years in training dataset
- Fits appear to capture characteristics of historical production profiles, but out of phase / time lagged
  - Could be due to non local wind speed data and complexity of wind propagation
  - Very poor R^2 values << 0.2
- How can we quantify goodness of fit?

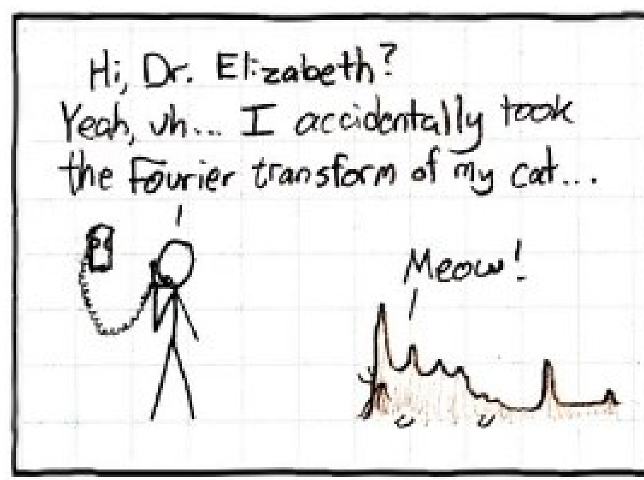
Fourier Analysis

- Converts time domain to frequency domain

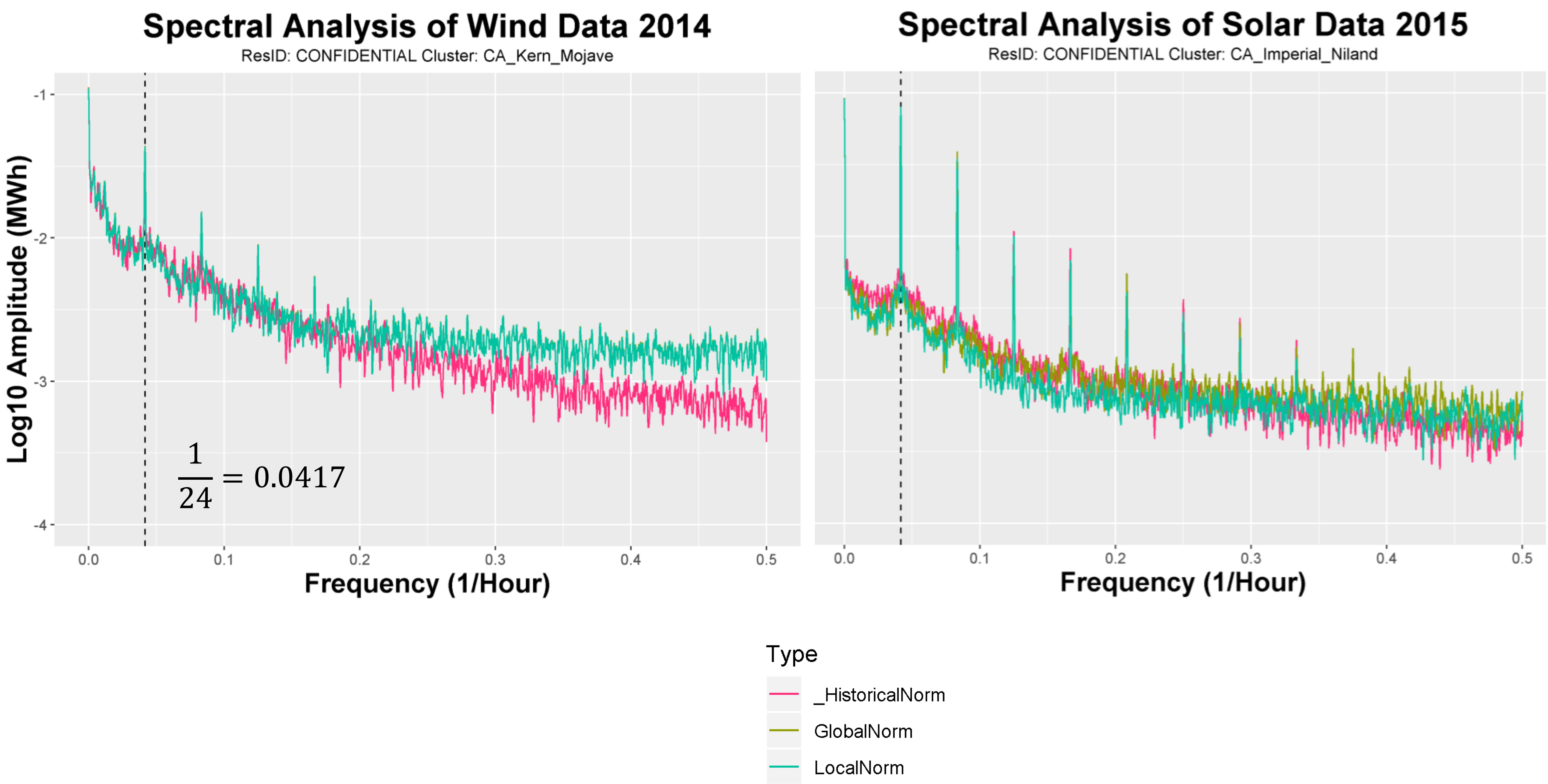


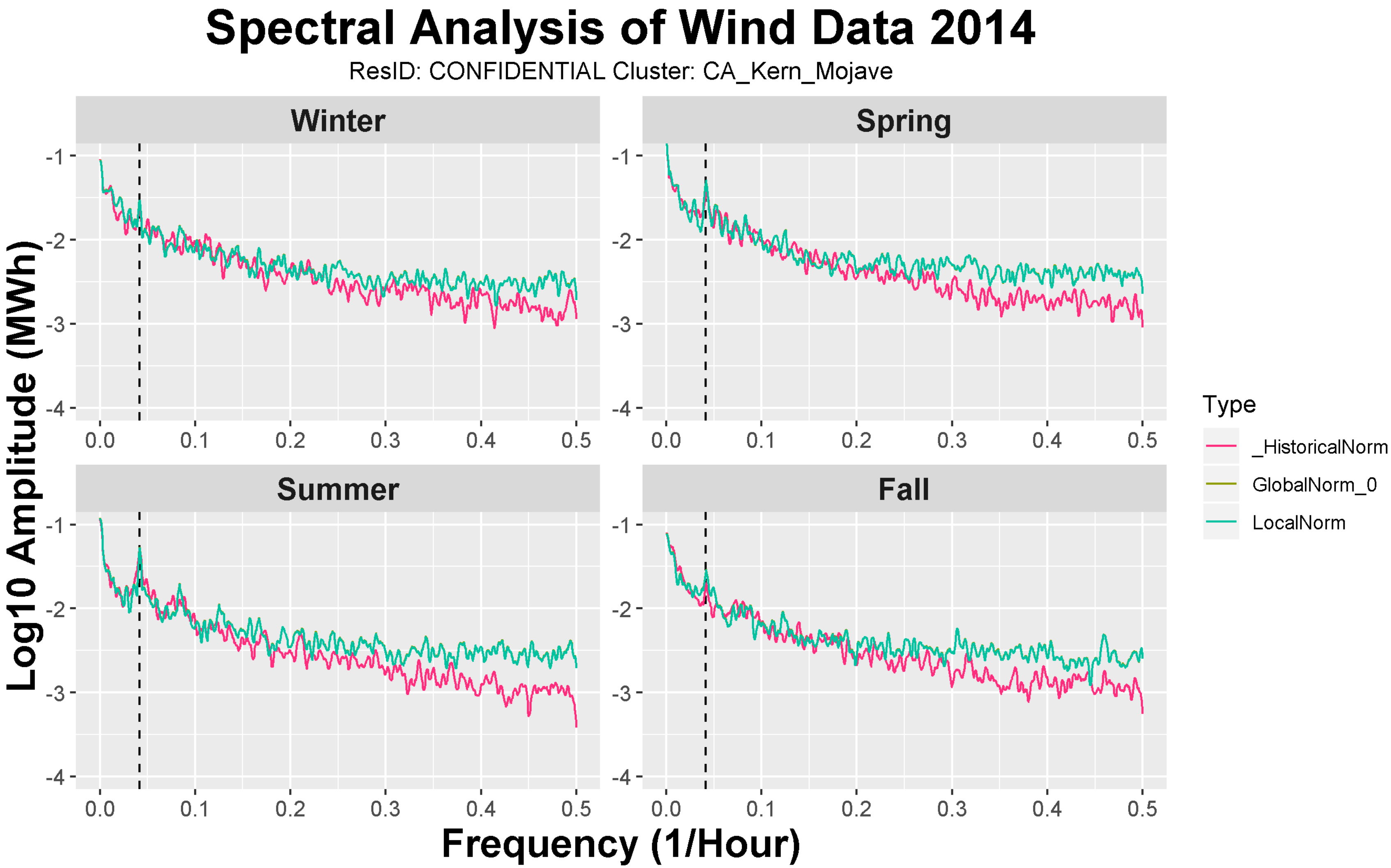
$$F(\omega) = \int_{-\infty}^{\infty} f(t) e^{-i\omega t} dt$$

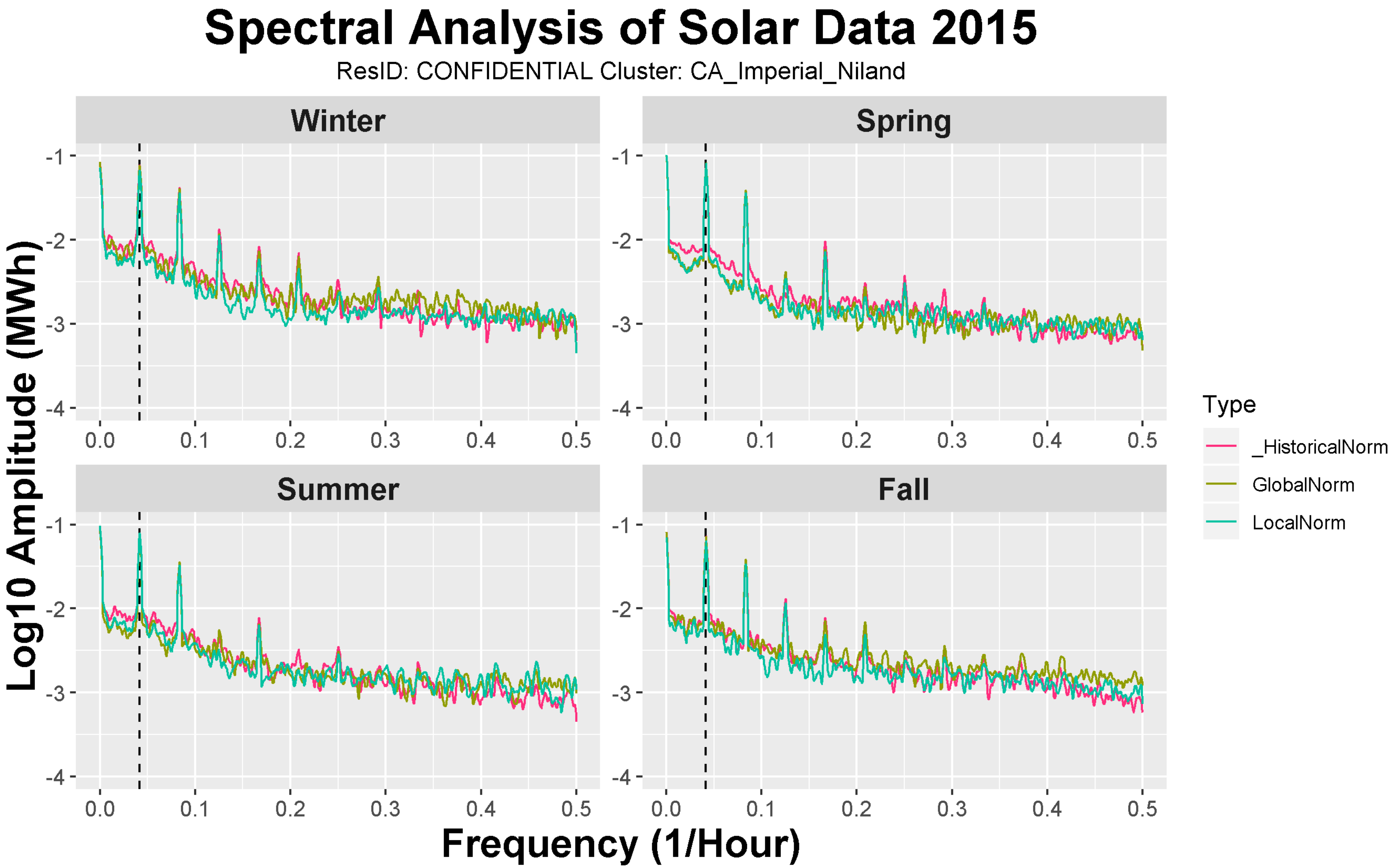
$$f(t) = \frac{1}{2\pi} \int_{-\infty}^{\infty} F(\omega) e^{i\omega t} d\omega$$



Spectral Analysis




Spectral Analysis of Wind Data 2014
ResID: CONFIDENTIAL Cluster: CA_Kern_Mojave
Winter
Spring
Summer
Fall
Log10 Amplitude (MWh)
Frequency (1/Hour)
-1
-2
-3
-4
0.0
0.1
0.2
0.3
0.4
0.5
Type
_HistoricalNorm
GlobalNorm_0
LocalNorm



Spectral Analysis of Solar Data 2015
ResID: CONFIDENTIAL Cluster: CA_Imperial_Niland
Winter
Spring
Summer
Fall
Log10 Amplitude (MWh)
-1
-2
-3
-4
0.0
0.1
0.2
0.3
0.4
0.5
Frequency (1/Hour)
Type
_HistoricalNorm
GlobalNorm
LocalNorm

Conclusions

- We have developed an automated machine learning approach for building synthetic solar and wind profiles
- Easy to update for next modeling cycle
- Solar model is quite accurate
- Wind model is understandably less accurate, but spectral analysis shows consistency with historical production profiles

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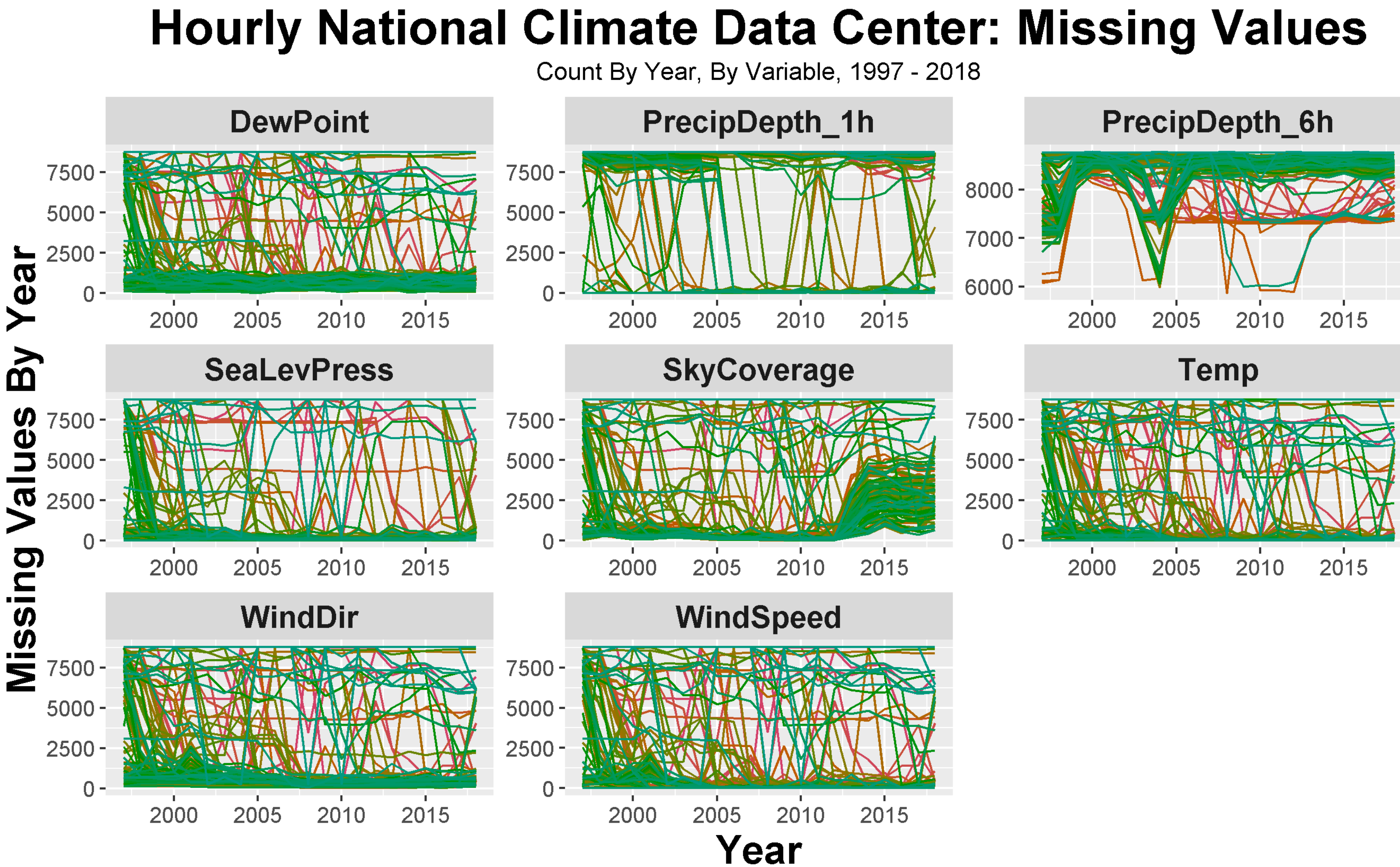
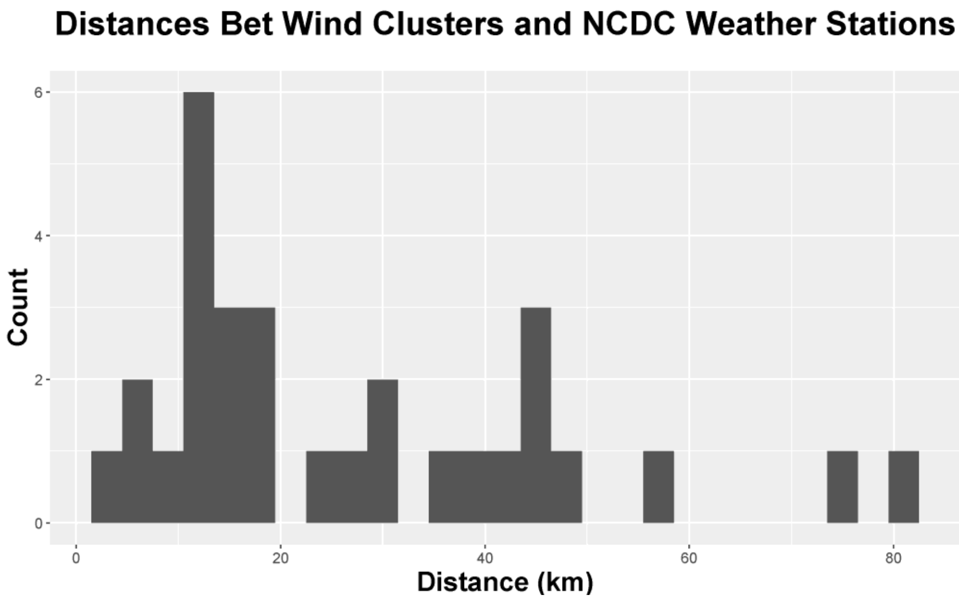
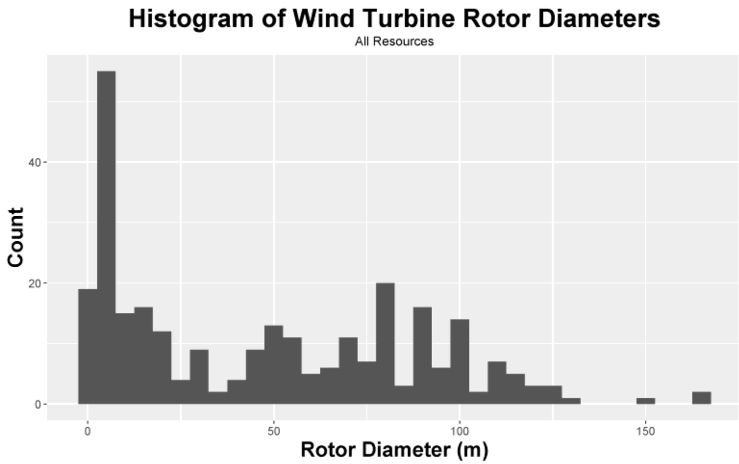
Additional Slides
Development of Hourly Wind and Solar Profiles

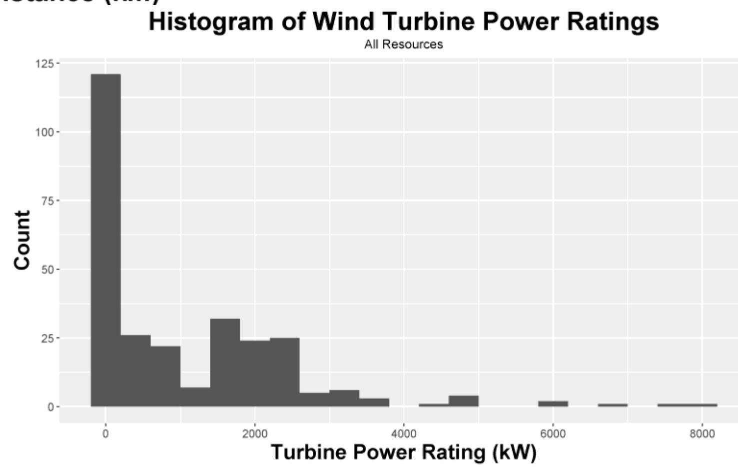


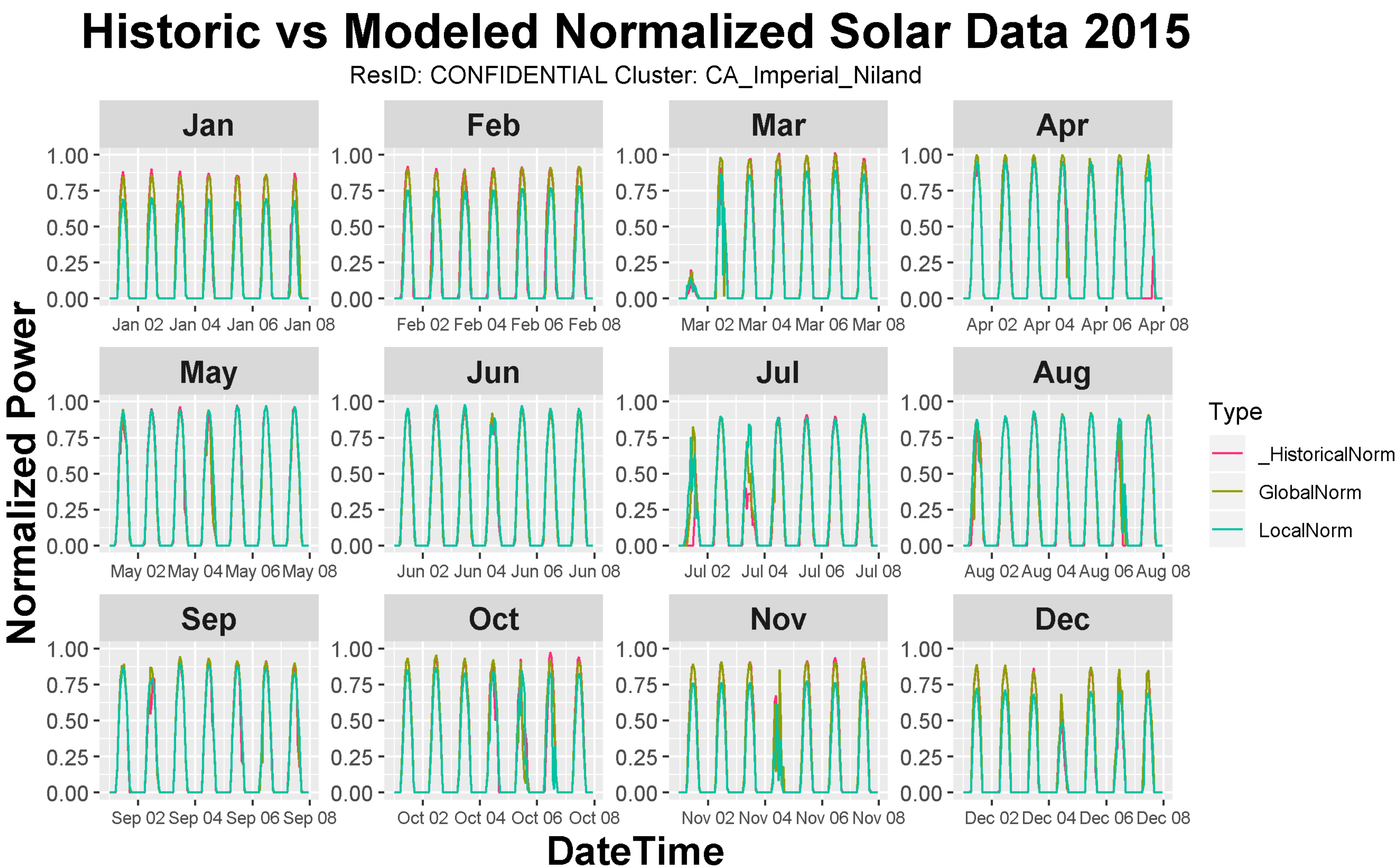
- Each line represents a single unique NCDC weather station

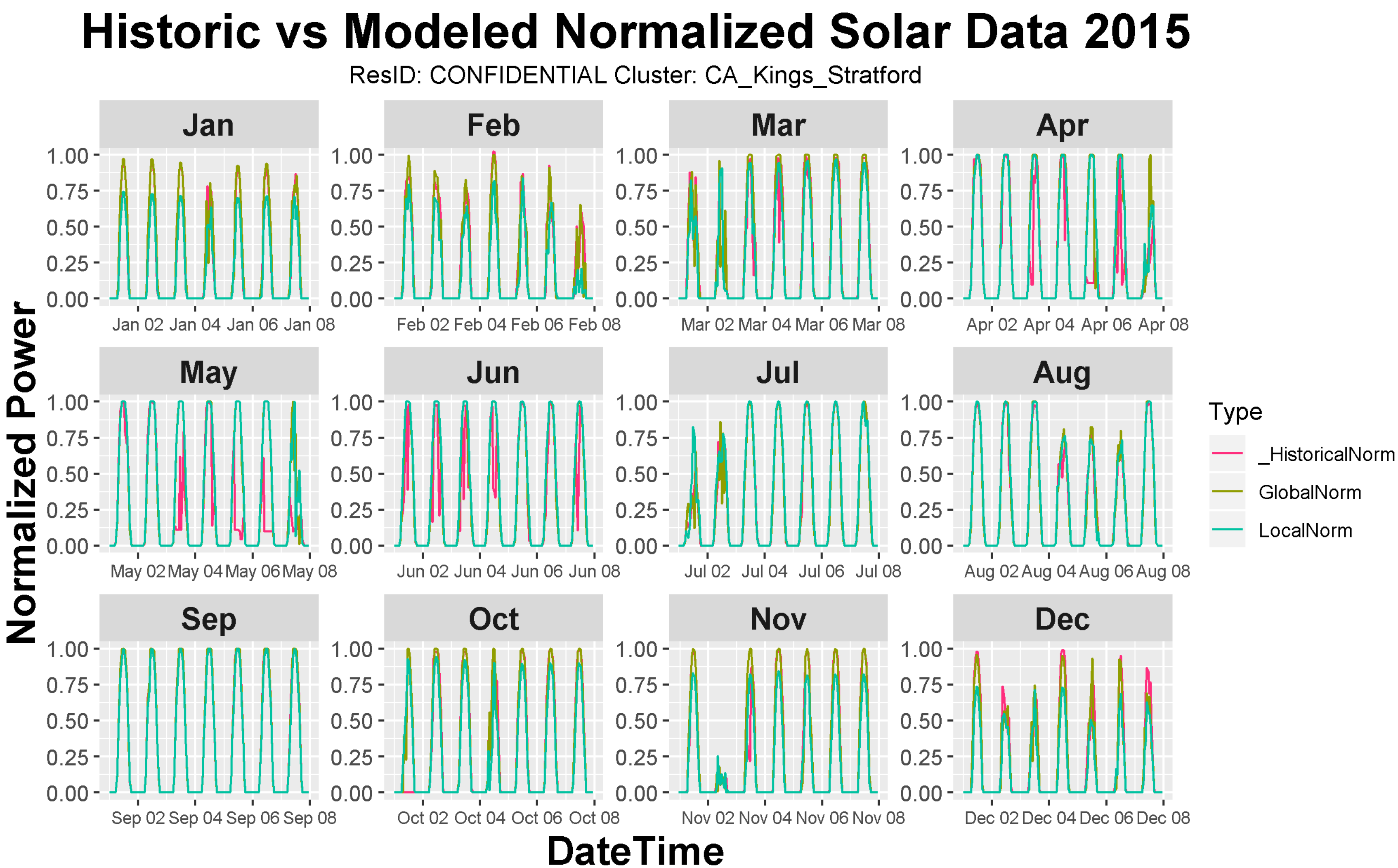
Wind Turbine Properties








Historic vs Modeled Normalized Solar Data 2015
ResID: CONFIDENTIAL Cluster: CA_Imperial_Niland
Jan
Feb
Mar
Apr
May
Jun
Jul
Aug
Sep
Oct
Nov
Dec
Normalized Power
1.00
0.75
0.50
0.25
0.00
Jan 02 Jan 04 Jan 06 Jan 08
Feb 02 Feb 04 Feb 06 Feb 08
Mar 02 Mar 04 Mar 06 Mar 08
Apr 02 Apr 04 Apr 06 Apr 08
May 02 May 04 May 06 May 08
Jun 02 Jun 04 Jun 06 Jun 08
Jul 02 Jul 04 Jul 06 Jul 08
Aug 02 Aug 04 Aug 06 Aug 08
Sep 02 Sep 04 Sep 06 Sep 08
Oct 02 Oct 04 Oct 06 Oct 08
Nov 02 Nov 04 Nov 06 Nov 08
Dec 02 Dec 04 Dec 06 Dec 08
DateTime
Type
_HistoricalNorm
GlobalNorm
LocalNorm


Historic vs Modeled Normalized Solar Data 2015
ResID: CONFIDENTIAL Cluster: CA_Kings_Stratford
Jan
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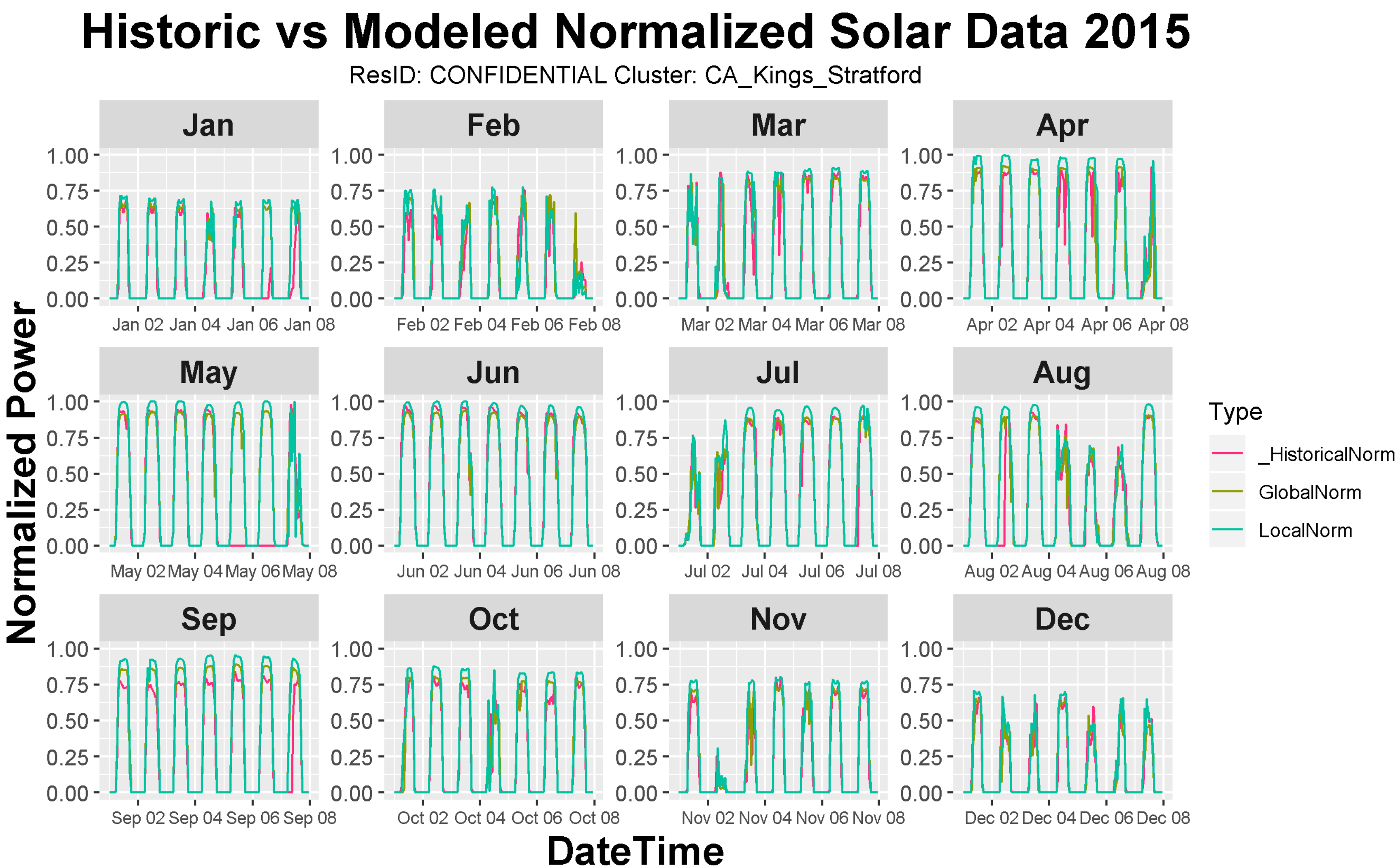
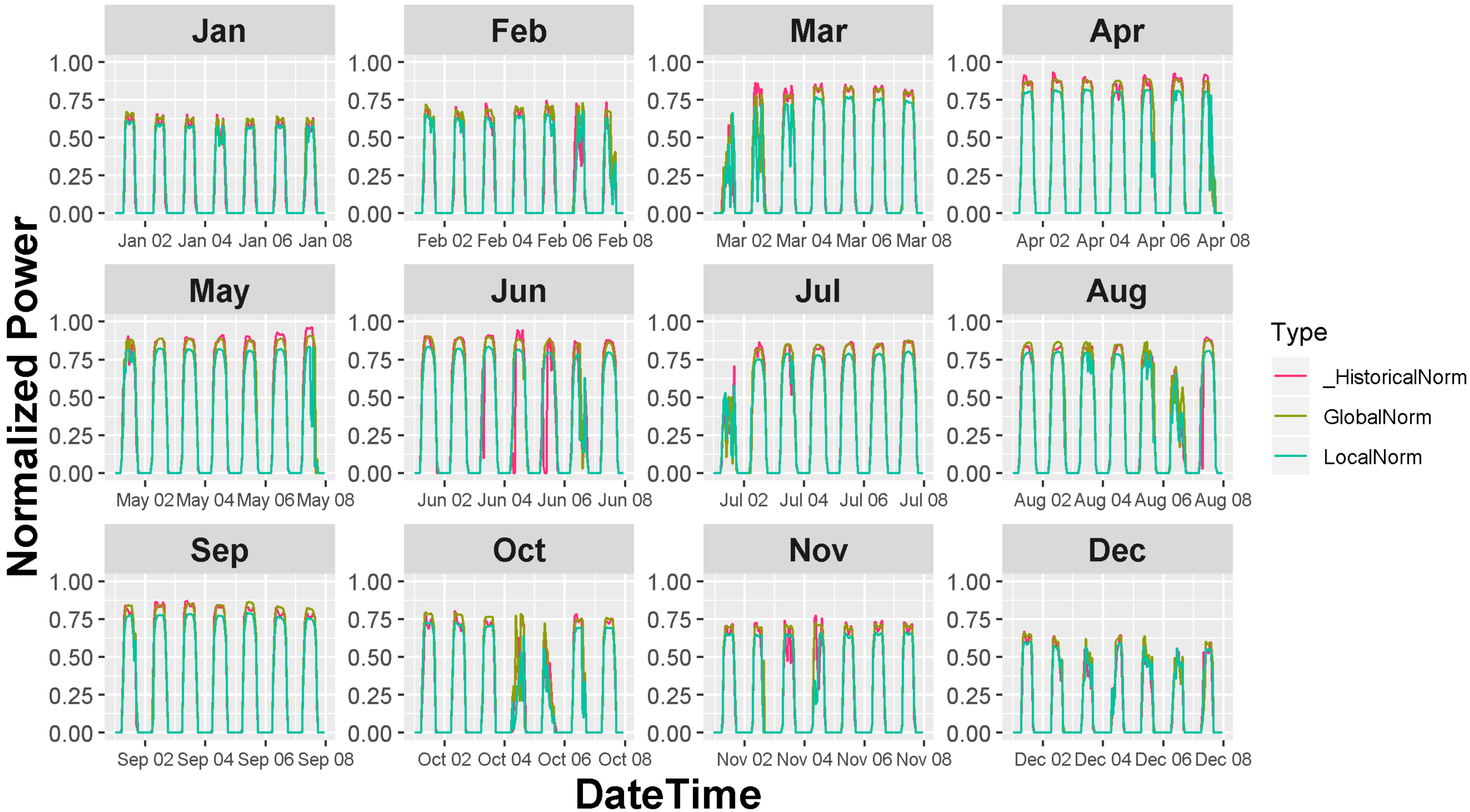
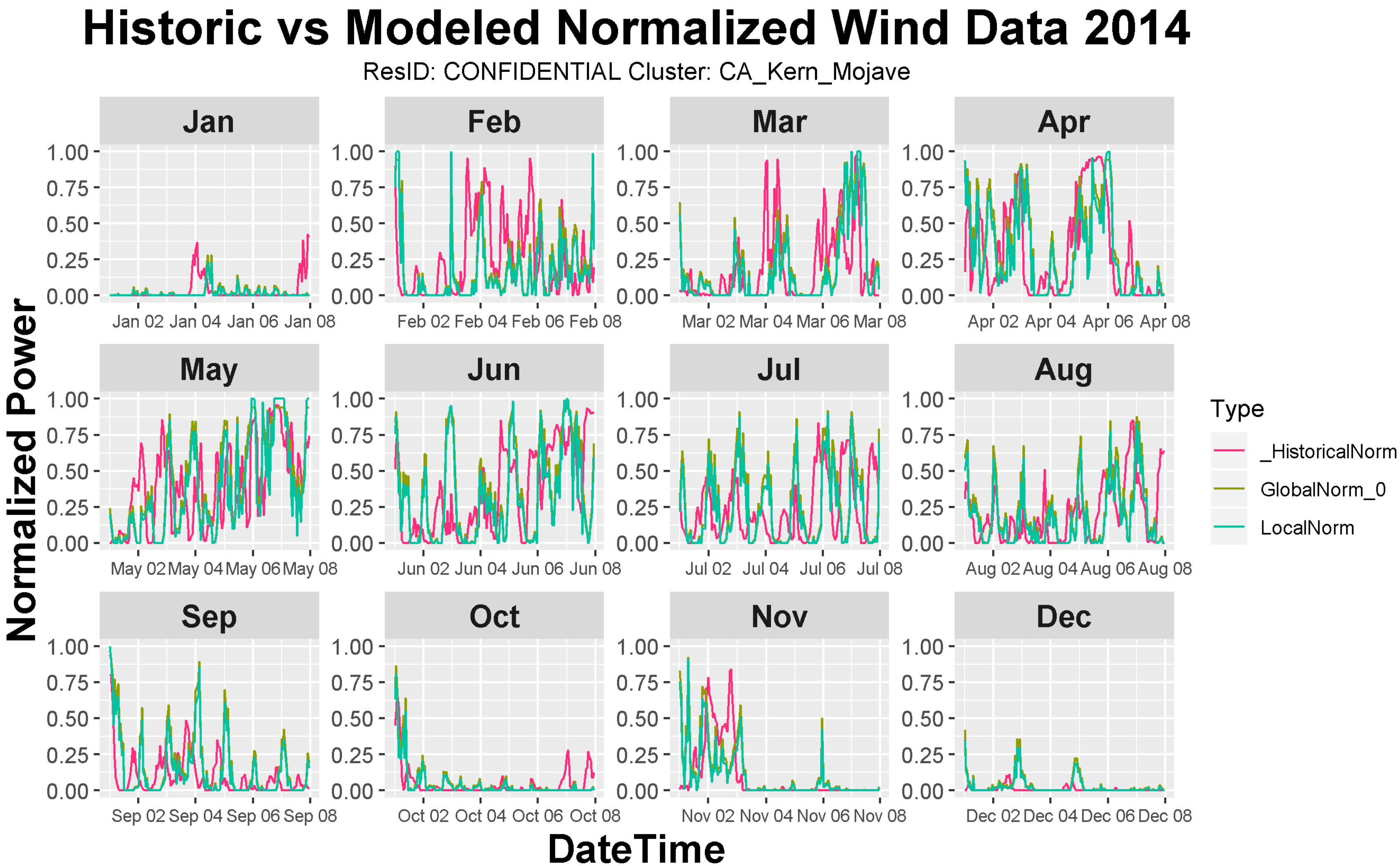
May
Jun
Jul
Aug
Sep
Oct
Nov
Dec
Normalized Power
1.00
0.75
0.50
0.25
0.00
Jan 02 Jan 04 Jan 06 Jan 08
Feb 02 Feb 04 Feb 06 Feb 08
Mar 02 Mar 04 Mar 06 Mar 08
Apr 02 Apr 04 Apr 06 Apr 08
May 02 May 04 May 06 May 08
Jun 02 Jun 04 Jun 06 Jun 08
Jul 02 Jul 04 Jul 06 Jul 08
Aug 02 Aug 04 Aug 06 Aug 08
Sep 02 Sep 04 Sep 06 Sep 08
Oct 02 Oct 04 Oct 06 Oct 08
Nov 02 Nov 04 Nov 06 Nov 08
Dec 02 Dec 04 Dec 06 Dec 08
DateTime
Type
_HistoricalNorm
GlobalNorm
LocalNorm


Historic vs Modeled Normalized Solar Data 2015
ResID: CONFIDENTIAL Cluster: CA_Kings_Stratford
Jan
Feb
Mar
Apr
May
Jun
Jul
Aug
Sep
Oct
Nov
Dec
Normalized Power
DateTime
Type
_HistoricalNorm
GlobalNorm
LocalNorm

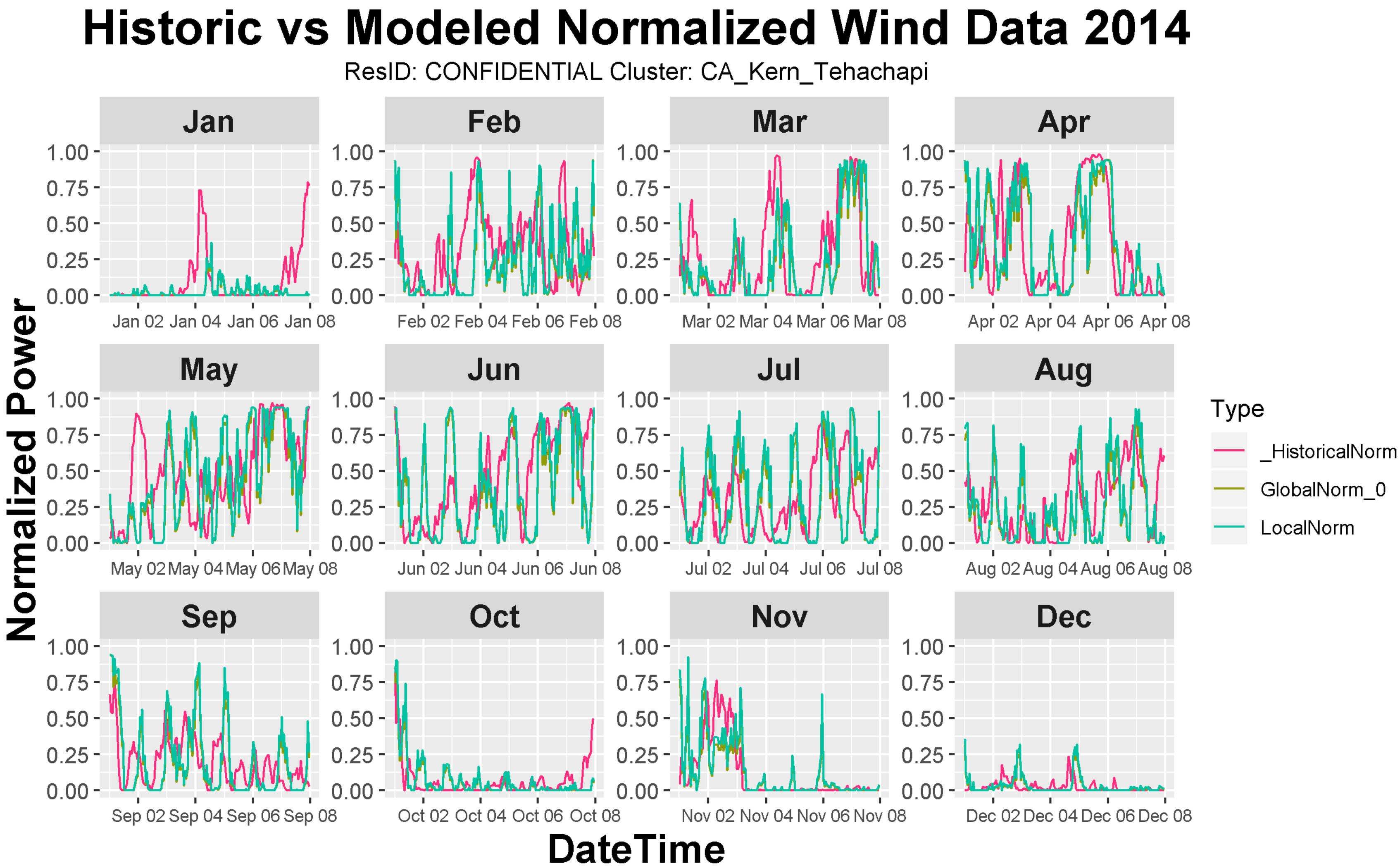
Historic vs Modeled Normalized Solar Data 2015

ResID: CONFIDENTIAL Cluster: CA_Kern_Rosamond





Historic vs Modeled Normalized Wind Data 2014
ResID: CONFIDENTIAL Cluster: CA_Kern_Mojave
Jan
Feb
Mar
Apr
May
Jun
Jul
Aug
Sep
Oct
Nov
Dec
Normalized Power
1.00
0.75
0.50
0.25
0.00
Jan 02 Jan 04 Jan 06 Jan 08
Feb 02 Feb 04 Feb 06 Feb 08
Mar 02 Mar 04 Mar 06 Mar 08
Apr 02 Apr 04 Apr 06 Apr 08
May 02 May 04 May 06 May 08
Jun 02 Jun 04 Jun 06 Jun 08
Jul 02 Jul 04 Jul 06 Jul 08
Aug 02 Aug 04 Aug 06 Aug 08
Sep 02 Sep 04 Sep 06 Sep 08
Oct 02 Oct 04 Oct 06 Oct 08
Nov 02 Nov 04 Nov 06 Nov 08
Dec 02 Dec 04 Dec 06 Dec 08
DateTime
Type
_HistoricalNorm
GlobalNorm_0
LocalNorm


Historic vs Modeled Normalized Wind Data 2014
ResID: CONFIDENTIAL Cluster: CA_Kern_Tehachapi
Jan
Feb
Mar
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May
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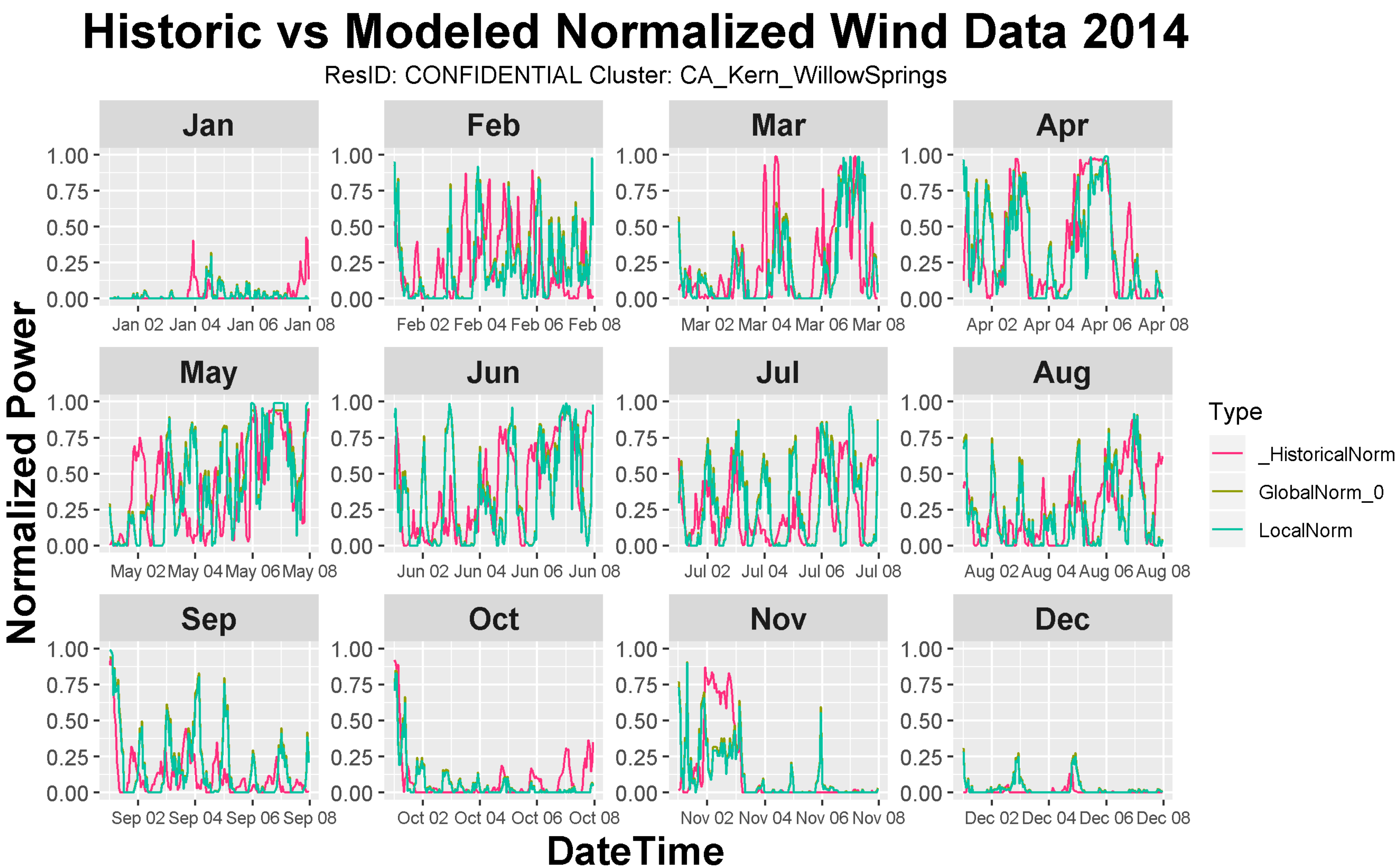
Jul
Aug
Sep
Oct
Nov
Dec
Normalized Power
1.00
0.75
0.50
0.25
0.00
Jan 02 Jan 04 Jan 06 Jan 08
Feb 02 Feb 04 Feb 06 Feb 08
Mar 02 Mar 04 Mar 06 Mar 08
Apr 02 Apr 04 Apr 06 Apr 08
May 02 May 04 May 06 May 08
Jun 02 Jun 04 Jun 06 Jun 08
Jul 02 Jul 04 Jul 06 Jul 08
Aug 02 Aug 04 Aug 06 Aug 08
Sep 02 Sep 04 Sep 06 Sep 08
Oct 02 Oct 04 Oct 06 Oct 08
Nov 02 Nov 04 Nov 06 Nov 08
Dec 02 Dec 04 Dec 06 Dec 08
DateTime
Type
_HistoricalNorm
GlobalNorm_0
LocalNorm


Historic vs Modeled Normalized Wind Data 2014
ResID: CONFIDENTIAL Cluster: CA_Kern_WillowSprings
Jan
Feb
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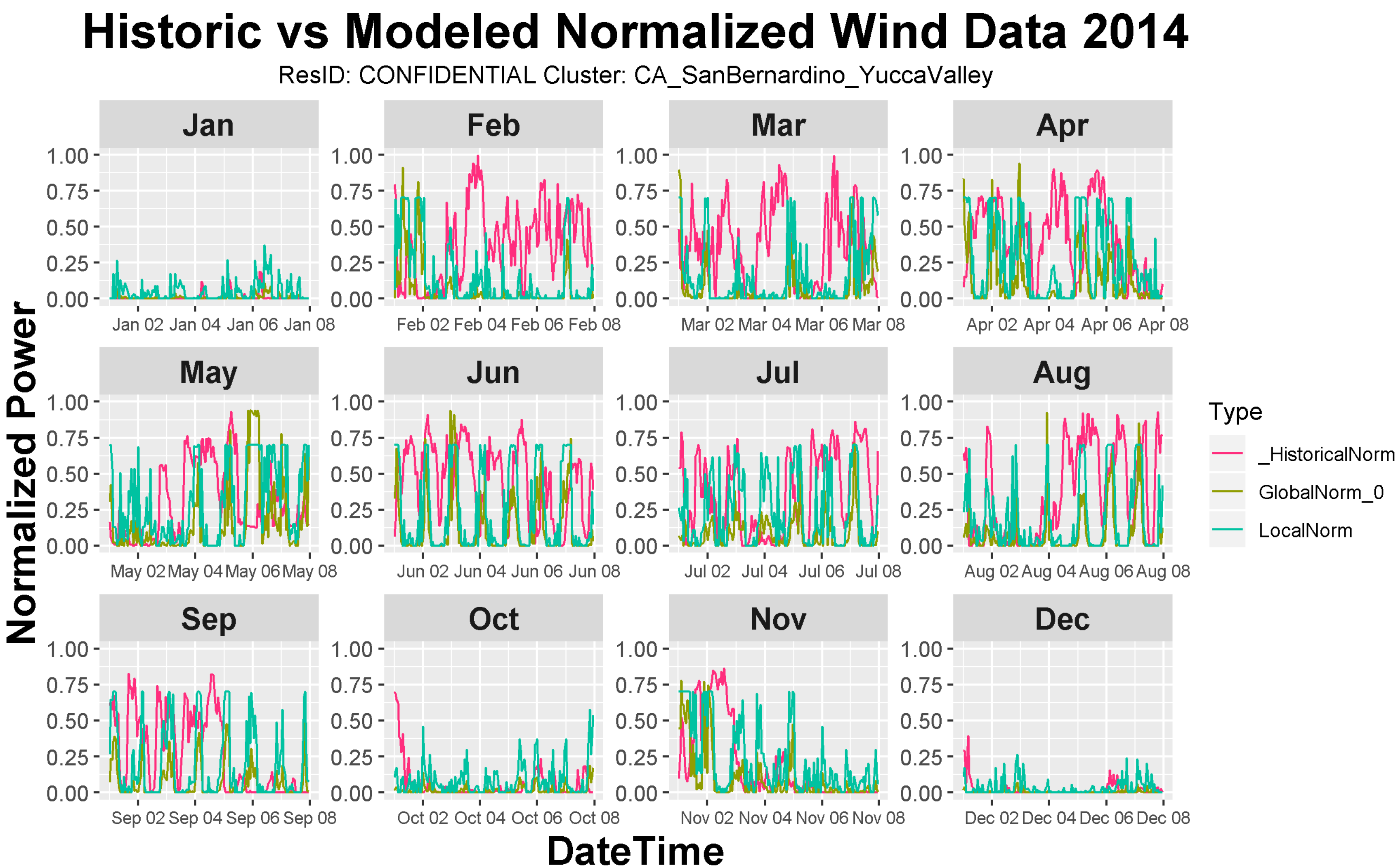
May
Jun
Jul
Aug
Sep
Oct
Nov
Dec
Normalized Power
DateTime
Type
_HistoricalNorm
GlobalNorm_0
LocalNorm



Historic vs Modeled Normalized Wind Data 2014
ResID: CONFIDENTIAL Cluster: CA_SanBernardino_YuccaValley
Jan
Feb
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Apr
May
Jun
Jul
Aug
Sep
Oct
Nov
Dec
Normalized Power
DateTime
1.00
0.75
0.50
0.25
0.00
Jan 02 Jan 04 Jan 06 Jan 08
Feb 02 Feb 04 Feb 06 Feb 08
Mar 02 Mar 04 Mar 06 Mar 08
Apr 02 Apr 04 Apr 06 Apr 08
May 02 May 04 May 06 May 08
Jun 02 Jun 04 Jun 06 Jun 08
Jul 02 Jul 04 Jul 06 Jul 08
Aug 02 Aug 04 Aug 06 Aug 08
Sep 02 Sep 04 Sep 06 Sep 08
Oct 02 Oct 04 Oct 06 Oct 08
Nov 02 Nov 04 Nov 06 Nov 08
Dec 02 Dec 04 Dec 06 Dec 08
Type
_HistoricalNorm
GlobalNorm_0
LocalNorm

VI. Revisions to modeling of NW hydro imports in RESOLVE

2017-18 IRP context

- In the 2017-18 IRP, specified hydro imports from the Pacific Northwest (NW) - via designated asset-controlling suppliers - were included in RESOLVE as a reduction in annual electricity supply GHG emissions
- The RESOLVE model also ensured that the imports into CAISO exceeded the GWh of historical NW imports into CAISO on an *annual* basis
  - For the Clean Net Short (CNS) calculator and other downstream uses of IRP analysis, an *hourly* representation of GHG emissions is desirable
- For the 2019-20 IRP, RESOLVE's representation of specified imports of hydro power from the Pacific Northwest has been revised to be more accurate and dynamic
  - <u>These changes remove the need for the annual “GHG offset” used in the 2017-18 IRP</u>

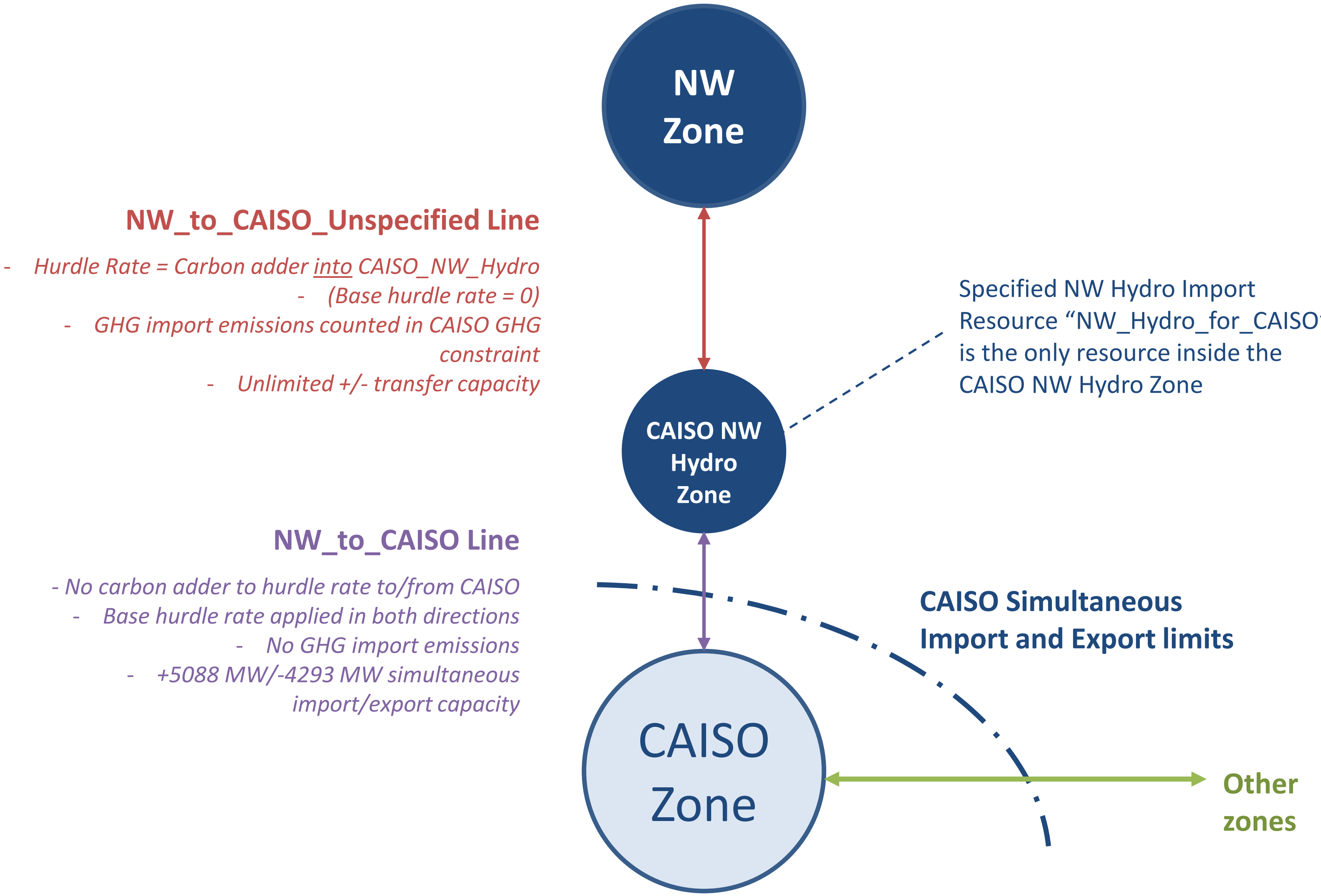
NW Hydro for CAISO Resource in RESOLVE

- New baseline resource “NW_Hydro_for_CAISO” added to represent GHG-free imports from designated asset-controlling suppliers under the CARB cap and trade program
  - Amount of NW_Hydro_for_CAISO available for import is based on average historical levels of Powerex and BPA imports
- NW_Hydro_for_CAISO is dispatched on an hourly basis
- Average and maximum daily capacity factor for NW_Hydro_for_CAISO resource match what is assumed for NW hydro resources
- NW_Hydro_for_CAISO energy budget is subtracted from the larger NW_Hydro resource to avoid double counting

Transmission Topology for Specified Imports of NW Hydro in RESOLVE

- New resource "NW_Hydro_for_CAISO" is located in a new zone called "CAISO_NW_Hydro"
  - Acts as a passthrough for unspecified imports from the NW
- Emissions from unspecified imports from the NW:
  - Are counted towards CAISO's GHG limit
  - Incur CARB cap and trade emission permit costs using CARB GHG intensity for unspecified imports
- Transfer limits into and out of CAISO are applied to the "NW_to_CAISO" transmission line between the CAISO zone and the CAISO_NW_Hydro zone
- The NW_to_CAISO line is subject to the simultaneous import and export limits between California and the Northwest

2019 IRP Transmission Topology of NW Hydro Imports in RESOLVE



VII. Approaches for Incorporation of Transmission Inputs

Transmission Capability Inputs for RESOLVE are Received from CAISO

- In accordance with a May 2010 MOU between CAISO and the CPUC
  - CPUC develops in coordination with the CEC the renewable resource portfolios used by CAISO in its annual transmission planning process (TPP)
  - The ISO periodically provides to the CPUC, the transmission capability estimates for major renewable resource zones for the specific purpose of providing input into portfolio development as part of the CPUC's IRP process
- The ISO published a white paper on May 20, 2019 and held a stakeholder call on May 28, 2019 to describe
  - The components and interpretation of transmission capability estimation
  - Sources of information used for estimating transmission capability; and
  - Steps involved in estimation of transmission capability and conceptual upgrade information.
  - http://www.caiso.com/Documents/WhitePaper-TransmissionCapabilityEstimates-InputtoCPUCIntegratedResourcePlanPortfolioDevelopment.pdf

Transmission Capability Estimate and Incremental Upgrade Cost Sources as Provided by CAISO

The primary source is generation interconnection studies; TPP studies is the supplementary source

1. **Current and past GIDAP studies (primary source of information)**
   – Lends itself particularly well to the transmission capability estimation effort
   – Amount of active generation in ISO's generation interconnection queue far exceeds the total generation resources that are typically selected as part of the portfolios
   – GIDAP assessments expose transmission constraints which typically would not be identified in the TPP assessments of generation amounts in the portfolios

2. **Current and past TPP studies**
   – ISO assesses the transmission impacts of renewable portfolios transmitted by the CPUC
   – Insights about the reliability impact of the portfolios on the transmission system, deliverability constraints that would limit portfolio resource deliverability and renewable curtailment observed in the production cost simulations
   – Act as a supplementary source of information for transmission capability estimation

California ISO

Page 13

California ISO Public

Slide Source: http://www.caiso.com/Documents/TransmissionCapabilityEstimates-CPUC-IRP-PortfolioDevelopmentRedacted.pdf

Input Estimates Received from CAISO

	Transmission capability estimates to support CPUC's IRP process (May 20, 2019)								
	Estimated FCDS Capability (MW)				Incremental Upgrade Cost Estimate ($million)				Estimated EODS Capability** (MW)
Transmission zones and sub-zones	Existing System	Minor Upgrades	Major Upgrade #1	Major Upgrade #2	Existing System	Minor Upgrades	Major Upgrade #1	Major Upgrade #2	Existing System
Northern CA	**2,000**		**2,000**				**$ 285**		**3,900**
- Round mountain	500								2,100
- Humboldt	-								100
- Sacramento River	2,000								4,600
- Solano	600		2,000				$ 322		1,300
Southern PG&E	**1,100**		**1,000**				**$ 55**		**TBD**
- Westlands	1,100		1,000				$ 55		TBD
- Kern and Greater Carrizo	1,000		1,500				$ 241		TBD
- Carrizo	400		700				$ 53		400
- Central Valley North & Los Banos	1,000		1,000				$ 274		TBD
Tehachapi	**4,300**	**1,000**				**$ 100**			**5,100**
Greater Kramer (North of Lugo)	600		400				**$ 146**		**600**
- North of Victor	300		400				$ 485		300
- Inyokern and North of Kramer	100		400				$ 485		100
- Pisgah	400		400				$ 261		400
Southern CA Desert and Southern NV	**3,000**		**2,800**				**$ 2,156**		**9,600**
- Eldorado/Mtn Pass (230 kV)	250		1,400				$ 76		2,400
- Southern NV (GLW-VEA)	700		1,400				$ 150		700
- Greater Imperial*	1,200		1,400				$ 2,334		3,100
- Riverside East & Palm Springs	2,950		1,500				$ 2,156		5,500

* Subject to mitigation of the S-line constraint.
** Estimate EODS capability numbers are inclusive of the FCDS estimates. So the incremental EODS capability = Estimated EODS capability - Estimated FCDS capability

NOTE:
(i) The transmission areas indented in the table are subsets of the overarching transmission areas listed immediately above the indented areas.
(ii) The transmission capability estimates rely on the latest generation interconnection studies as one of the inputs. Estimated available transmission has been reduced by the amount of renewable resources that have come online by December 31, 2018 assuming that all these resources have a contract with an entity within CAISO BA.
(ii) The estimated capability added due to major upgrades and corresponding costs are ballpark numbers and are conceptual in nature.

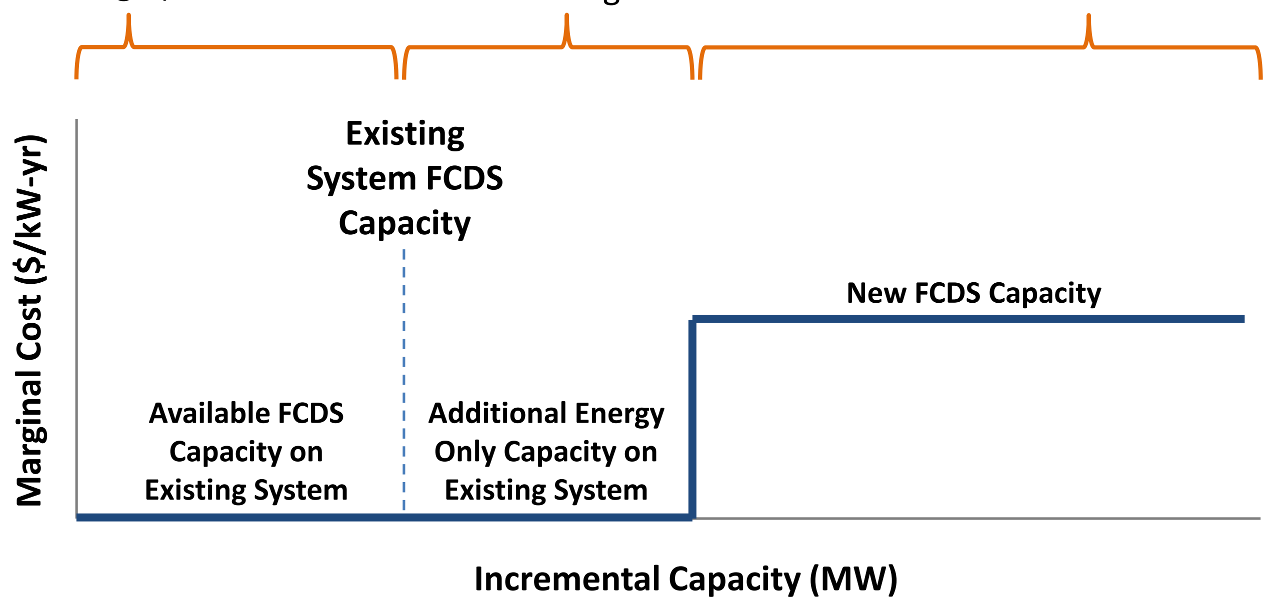
California In-State Renewable Transmission Cost and Potential

- Each renewable resource zone in RESOLVE contains some mix of candidate renewable resources

Renewables within each zone compete with one another for existing, zero marginal cost FCDS transmission capacity. RESOLVE will typically prioritize FCDS for resources with a higher peak capacity contribution (MW that a resource contributes to meeting the planning reserve margin)

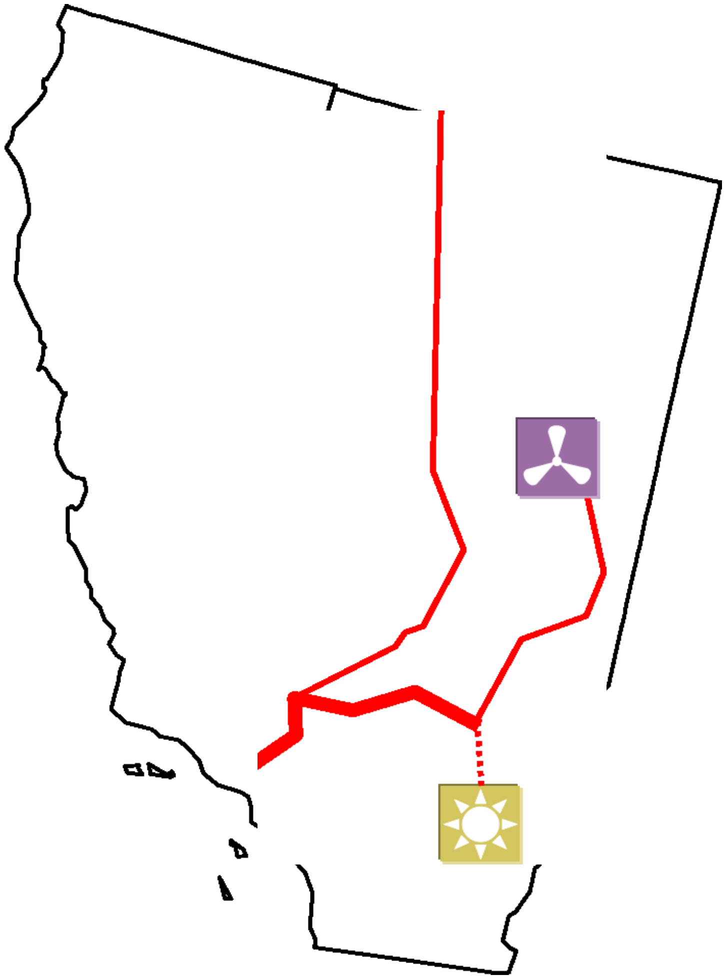
RESOLVE can also select renewables to have energy only (EO) status on the existing transmission system if EO capacity is available. In this case, the renewable resource does not contribute to the meeting the planning reserve margin.

Additional transmission capacity can be built at an incremental cost. All new transmission is FCDS.



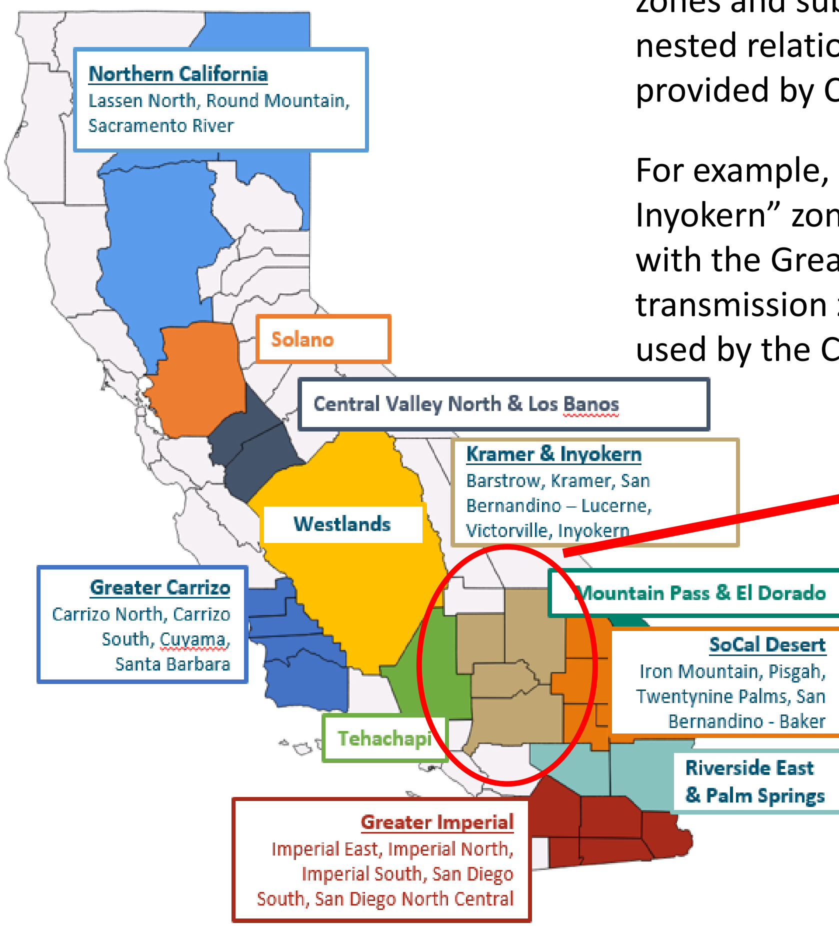
Overview of Modeling of Transmission in RESOLVE

- Transmission costs split in three categories
  - Interconnection Cost
    - Gen-tie line + substation
  - Delivery Network Upgrades (minor and major upgrades)
  - Out-of-state Transmission
- The estimates received from CAISO inform Delivery Network Upgrades costs.
- Transmission costs factor into optimal resource selection



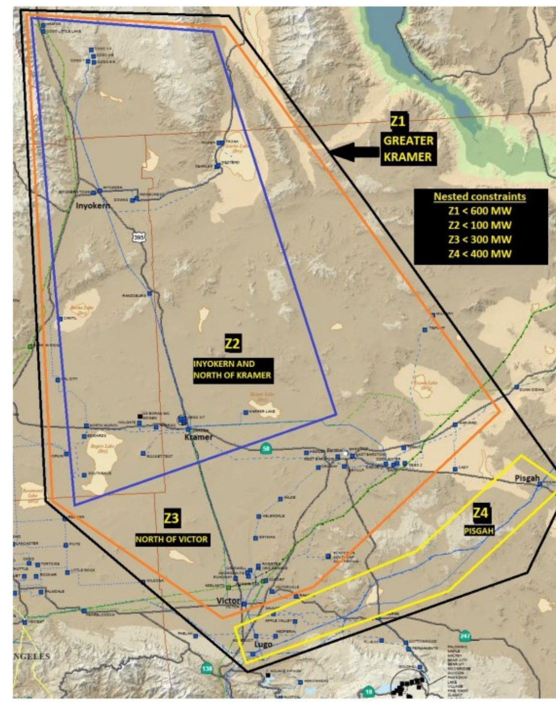
RESOLVE Resource Zones Need to Incorporate Updated CAISO Transmission Capability Geography

California Resource Zones Available in RESOLVE



In many cases the RESOLVE renewable resource zones are not consistent with the transmission zones and sub-zones, and the nested relationships that were provided by CAISO recently

For example, RESOLVE's "Kramer & Inyokern" zone does not align well with the Greater Kramer transmission zone and subzones used by the CAISO



Map above right: CEC map with CAISO overlay
Source: http://www.caiso.com/Documents/WhitePaper-TransmissionCapabilityEstimates-InputtoCPUCIntegratedResourcePlanPortfolioDevelopment.pdf

Guiding Principles for Incorporating CAISO Transmission Estimates into RESOLVE

- Consider relative costs, benefits, and risks of various solutions
  - Transmission costs are only one of multiple factors considered
  - Solutions may include for example:
    - Build new transmission to access more renewable resource capacity in certain areas
    - Build generation resources in different transmission zone
    - Pursue non-wire solutions – such as energy storage – that do not require transmission upgrades
- Only trigger investment in transmission for which there is a demonstrated need
  - Do not trigger transmission upgrades if not necessary and/or cost effective

Proposed Approach for Incorporating CAISO Transmission Estimates into RESOLVE

- Develop a method for handling nested constraints of CAISO sub-zones. Options considered include:
  - **Option 1:** Re-code RESOLVE based on newly provided CAISO estimates to include more geographic granularity. Use mathematical constraints provided by the CAISO for transmission zones and sub-zones to ensure that all constraints are met simultaneously
    - Would require significant model development and lead-time. Not feasible for staff to complete this in time for the RESOLVE model runs which begin in July.
  - **Option 2:** Reduce capacity of subzones to ensure that the subzone and zone constraints are met. Prioritize full deliverability of renewable resources with higher marginal capacity value.
    - 2A: Reduce subzone capacity *before* the RESOLVE optimization so that every RESOLVE portfolio does not exceed transmission limits.
    - 2B: Reduce subzone capacity *after* the RESOLVE optimization for a handful of portfolios – especially those sent to the CAISO TPP – by re-locating a limited set of selected resources until transmission limits are met.
- Staff needs to determine which of the above options, or combination of options, is the best feasible approach
  - Staff will begin by verifying that resource potential in RESOLVE is appropriately grouped to the transmission zones in CAISO table

Questions for Parties

- Do parties have suggestions on how CPUC staff should adhere to the nested transmission zone capability estimates provided by the CAISO? Would you recommend option 2a, 2b, or another approach, and why?
- The CAISO data includes cost estimates for major upgrades to transmission zone capability. Should considerable time and effort be spent developing a smoother cost profile for transmission investments such that RESOLVE could select smaller increments of transmission upgrades? If so, how?
- RESOLVE currently does not allow for the build of new transmission to increase EO capability alone. The CAISO data also do not provide any information regarding the cost of transmission upgrades to only increase EO capability. Is this something that should be further considered by CPUC staff?

Wrap Up/Next Steps

Request for Modeling Advisory Group feedback

- CPUC staff requests informal feedback from the Modeling Advisory Group on the Reference System Portfolio modeling process and core inputs presented here
- Staff will post the core datasets for review by this Group and will set a deadline for providing informal comments at that time – notifications will be announced to the proceeding service list
- Informal comments shall be emailed to the IRP proceeding service list and specifically be addressed to the following CPUC staff contacts:

  Patrick Young – patrick.young@cpuc.ca.gov

  Nathan Barcic – nathan.barcic@cpuc.ca.gov

Questions?

- Thank you for your participation and please contact the staff below with any questions you have about this presentation.

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Important links:

IRP Events and Materials

Modeling Advisory Group