Integrating Renewables in Jiangsu Province, China

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energynautics solutions for sustainable development

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Introduction

Jiangsu Province

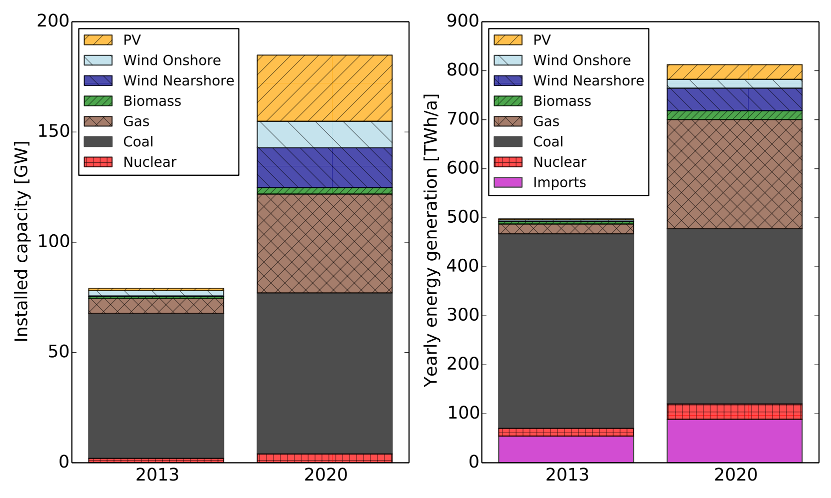
- Jiangsu is a highly industrialised Province on the east coast of China (north-west of Shanghai)
- Population around 80 million
- Peak load of 80 GW in 2014
- Population and load comparable to Germany; area three times smaller

Source: Wikipedia

Greenpeace Energy [R]evolution for Jiangsu in 2020

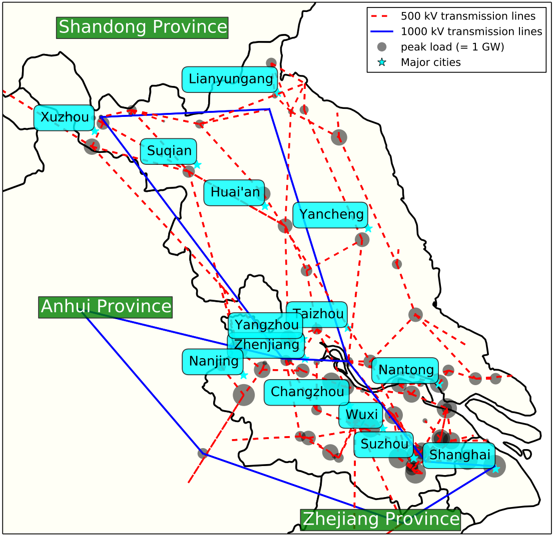
- China 15% non-fossil primary energy target by 2020
  $\implies \sim 30\%$ renewable electricity by 2020 (currently $\sim 23\%$ RE)
- Today 80% of electricity in Jiangsu comes from locally-burned coal, with 11% imports and some nuclear, gas and wind
- In 2013 around 2.5 GW of wind and 1 GW of PV in Jiangsu (1% RE)
- By 2020 government plans 10 GW each of wind and solar (5% RE)
- Greenpeace Energy [R]evolution 3 times as ambitious:
  30 GW of wind, 30 GW of PV and 3 GW of biomass by 2020
- Jiangsu would then cover 14% of demand with local renewables; 17% if renewable imports included
- Greenpeace East Asia commissioned Energynautics to investigate consequences for Jiangsu's power system

Greenpeace Energy [R]evolution for Jiangsu in 2020



Data Inputs & Methodology

Network Model of Jiangsu

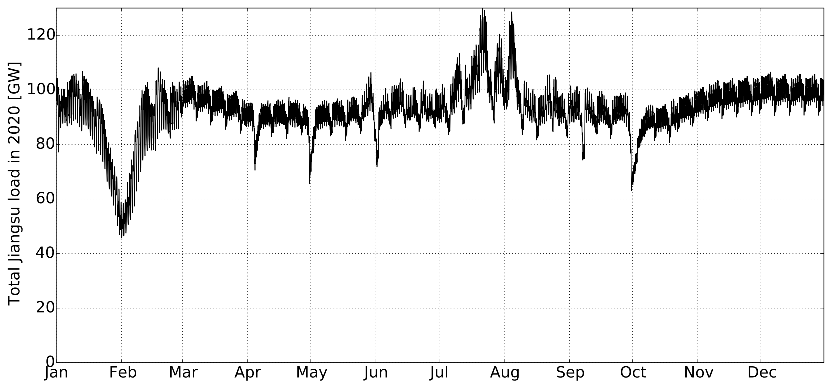


- Load mostly in south (grey circles)
- Backbone of transmission network is 500 kV network (red)
- Inter-province 1000 kV lines under construction (blue)

Generation capacities

Source	Capacity in 2013 (GW)	Capacity in 2020 (GW)	Full Load Hours	Capacity factor (%)
Wind onshore	2.3	12.0	1510	17.1
Wind nearshore	0.2	18.0	2550	29.1
Solar PV	1.0	30.0	1000	11.4
Biomass	0.9	3.0	6000	68.5
Coal	65.7	73.0	4903	56.0
Gas	6.9	45.0	4960	56.6
Nuclear	2.0	4.0	7885	90.0
Pumped-Hydro	1.1	1.1		
Peak load	80.0	130.0		

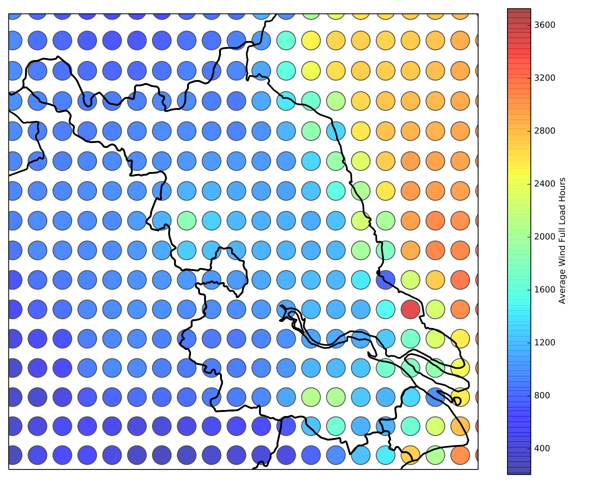
Load curve for 2020



Load minimum during Spring Festival in February;

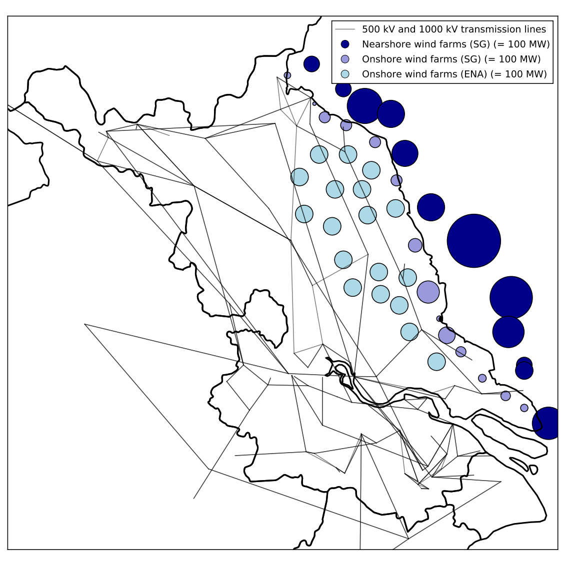
air-conditioning peak in late July.

Wind Full Load Hours from REatlas



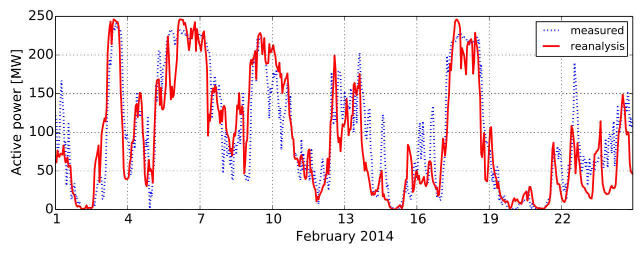
- Wind and solar data from RE Atlas from Aarhus University
- Provided hourly for 2014 for 480 points
- Wind FLH best in sea and along coastline

Wind Park Placement

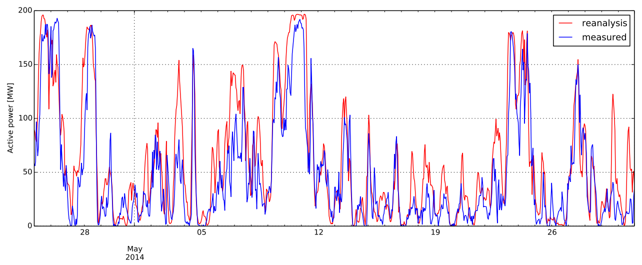


- Plans already for 18 GW of nearshore and first 3 GW of onshore
- Remaining 9 GW of onshore placed by us
- Poor inland sites reduce onshore FLHs from $\sim$ 1950 to $\sim$ 1500

Comparison of REatlas to measured data



Dongtai Wind Park in February 2014



Dafeng Wind Park in April/May 2014

Methodology for Network Extension Calculation

Optimal Power Flow performed with Energynautics' ENAPLAN tool to minimise necessary grid extensions. Objective function for each hour is:

$$f(\mathbf{d}_{g,i,t}, \mathbf{P}_\ell) = \sum_{g,i} c_g \mathbf{d}_{g,i,t} + \sum_\ell c_\ell \mathbf{P}_\ell$$

$c_\star$ are costs (line extension costs dominate); $\mathbf{d}_{g,i,t}$ is dispatch of technology g at node i and time t; $\mathbf{P}_\ell$ is additional capacity of line ℓ. Constraints:

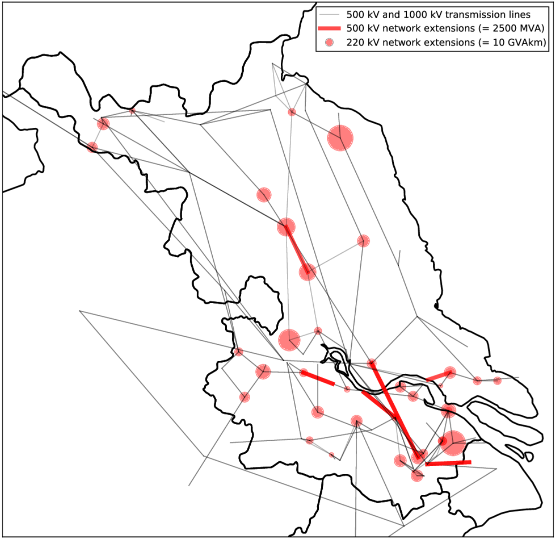
$$\begin{aligned}
D_{g,i} \quad &\geq \quad D_{g,i,t} \geq \mathbf{d}_{g,i,t} \geq \hat{D}_{g,i,t} \qquad \text{(Generator)} \\
s\mathbf{P}_\ell + s\hat{P}_\ell \quad &\geq \quad |p_{\ell,t}| = \left| \sum_i PTDF_{\ell i}\, p_{i,t} \right| \qquad \text{(Linear power flow)} \\
p_{i,t} \quad &= \quad \sum_g \mathbf{d}_{g,i,t} - \ell_{i,t} \qquad \text{(Nodal power imbalance)} \\
0 \quad &= \quad \sum_i p_{i,t} \qquad \text{(Global power balance)}
\end{aligned}$$

Results

Scenario Assumption and Results

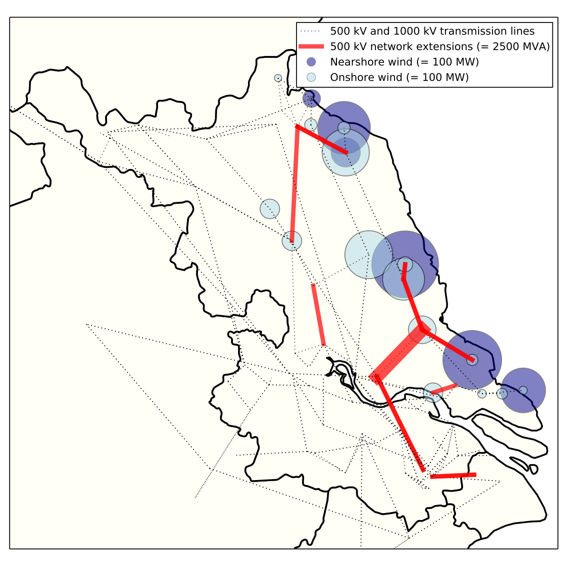
Scenario	Description
Load Expansion Only	No RE, just load increase
Basis	With RE
Dynamic RE	With RE and DLR
Unlimited Wind Management	With RE and curtailment to 0%
2% Wind Management	With RE and curtailment to 70%
1% Wind Management	With RE and curtailment to 80%
Lower Load, No RE	No RE, peak load just 113.5 GW
Lower Load, With RE	With RE, peak load just 113.5 GW

Load Extension Only Scenario (No RE)



- Rising load alone requires 2200 GVAkm of network extensions by 2020
- Corresponds to a 3.3% increase in the capacity of the network model
- Costs of 4.4 billion Yuan

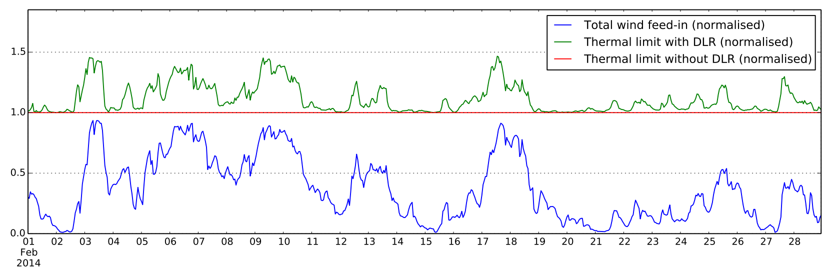
Basis Scenario



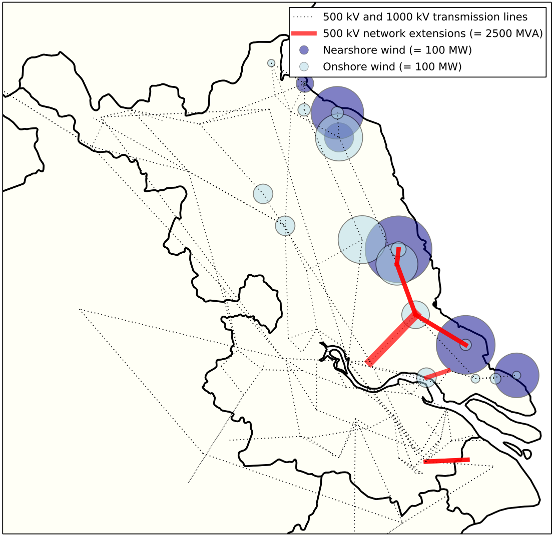
- Build out determined by wind feed-in along coastline
- Network extensions cost only 52% more than Load Expansion Only scenario
- Increase of 5.1% over already-planned network (in MVAkm)

Dynamic Line Rating

Dynamic Line Rating (DLR) can safely raise the thermal limits when there is an additional cooling of the overhead transmission lines due to the wind and cold outside temperature.

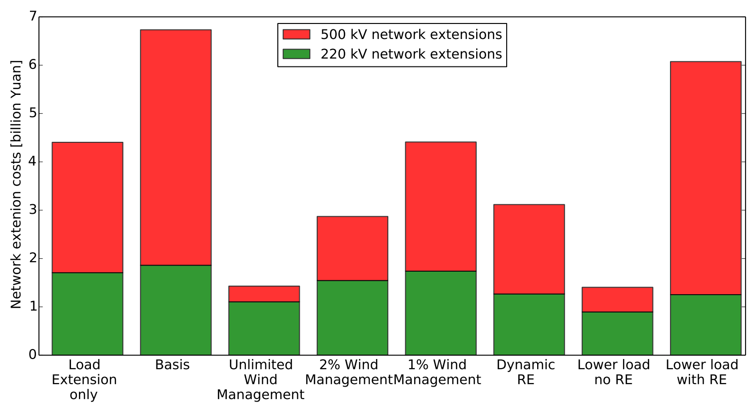


Dynamic RE Scenario



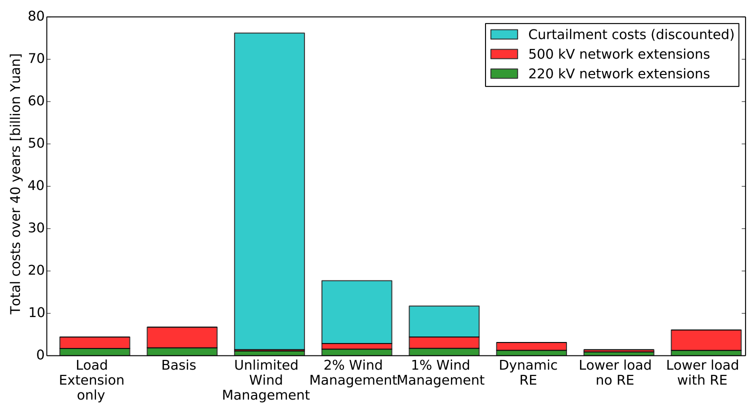
- Same RE capacity as Basis scenario
- DLR allows us to avoid over half of network extension costs
- DLR raises capacity at same time that wind feed-in overloads network

Scenario Results: Costs for Network Extensions

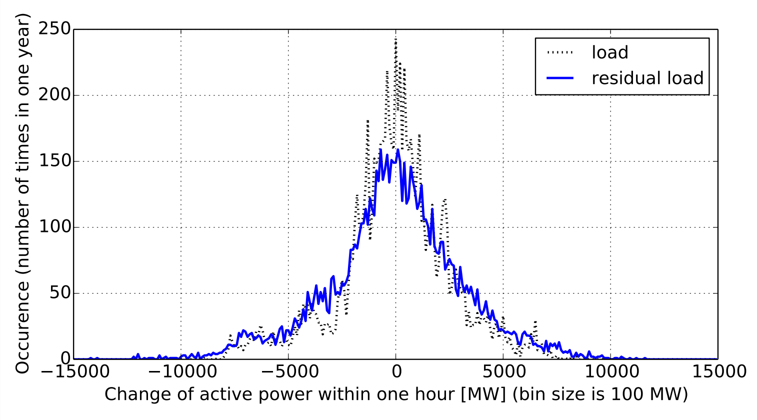


Cost assumption: 2000 Yuan/MVA/km for network extension.

Scenario Results: Costs for Network Extensions and Curtailment over 40 years

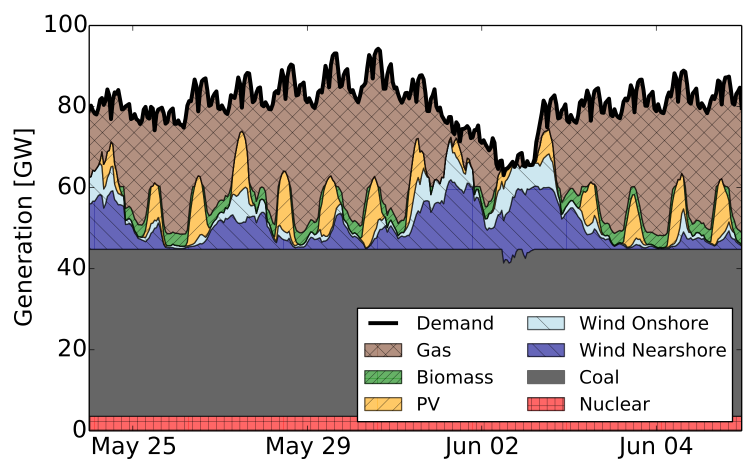


Histogram of changes to the load and residual load within one hour for the Basis scenario in 2020:



Two-Week Dispatch

Coal run as baseload, unless forced down by residual load:



Conclusions

Conclusions

- Jiangsu can triple its RE targets for 2020 and thus meet 14% of its electrical demand from local renewables.
- Some grid upgrades are necessary to accommodate the predicted rise in load and transport wind from the coast to load centres...
- ...but over half of the extensions can be avoided by using technologies such as Dynamic Line Rating, which raises grid capacities where there is a cooling effect due to the wind.
- The additional grid extensions are small (2-3%) compared to the planned network size and the annualised grid extension costs are minimal ($\sim$ 0.05%) compared to annual electricity costs.