

# A Clash of Competing Necessities

## Water Adequacy and Electric Reliability in China, India, France, and Texas

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Vice President for Public Research

## Abstract

This report describes the application of a new mixed-integer linear programming model of the power sector that accounts for water used for thermal cooling. The model is used to explore a series of scenarios for each of four case studies—the North Grid of China, India, France, and the state of Texas in the United States. For each case study we developed a baseline projection, then modeled a number of scenarios, including limits on water availability, reduced power demand from end-use energy efficiency, expansion of renewable energy, and carbon caps. We provide model output, including water withdrawals and consumption; power generation fuel mix; carbon dioxide emissions; and total system, fixed, and variable costs. Documentation of the model is provided in an appendix. We developed a set of recommended strategies from this analysis, which are presented in detail in a companion report, *Capturing Synergies Between Water Conservation and Carbon Dioxide Emissions in the Power Sector*.

## Executive Summary

Four case studies—applying a new model of the power sector that captures the key relationships with water—have provided a more thorough understanding of potential conflicts and synergies between power generation and water. The areas studied are the North Grid of China, India, France, and the state of Texas in the United States. We chose these cases because water is posing challenges to power generation in each of them.

Using a mixed-integer linear programming model developed for this project, we produced a baseline projection for each case study, then modeled a number of scenarios, including limits on water availability, reduced power demand from end-use energy efficiency, expansion of renewable energy, and carbon caps, among others.

In this report, we provide model output, including water withdrawals and consumption; power generation fuel mix; carbon dioxide emissions; and total system, fixed, and variable costs. Documentation of the model is provided in an appendix.

## Findings and Recommendations

Our principal finding is that cost-effective options exist that can cut water used in electricity generation and also reduce emissions of conventional pollutants and carbon dioxide.

From the analysis of the case studies, we developed a set of recommended strategies, which are presented in detail in a companion report, *Capturing Synergies Between Water Conservation and Carbon Dioxide Emissions in the Power Sector*.<sup>1</sup>

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<sup>1</sup> Faeth, Paul, and Benjamin K. Sovacool. *Capturing Synergies Between Water Conservation and Carbon Dioxide Emissions in the Power Sector*. July 2014. CNA Corporation. IRM-2014-U-008090.

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## Next Steps

Electricity generation from thermoelectric power plants is inextricably linked to water resources at nearly all stages in the power production cycle, yet this critical constraint has been largely overlooked in policy and planning. While this assumption suggests that water is inexpensive and abundant, global water resources are increasingly strained by economic development, population growth, and climate change. As demand increases, competition for limited water resources among the agricultural, industrial, municipal, and electric power sectors threatens to become acute in several global regions. The intent of the research was to better appreciate the issues at play and put forward a set of strategies to reduce the dependence on water of the power sector, thereby enhancing its reliability as well as the water- and pollutant-related co-benefits that could be derived.

It is critically important that policymakers, government officials, and other decision makers and interested parties are aware of the significant reliability risks increasingly posed by water resource constraints. A key takeaway from the work reported here is that tools that enable the full consideration of water-related conflicts and synergies need to be developed and applied in order to avoid those future risks.

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# Glossary

bcm	billion cubic meters
BP	British Petroleum
CBM	coal-bed methane
CCGT	combined-cycle gas turbine
CCS	carbon capture and storage/sequestration
CERC	Central Electricity Regulatory Commission (India)
CREZ	Competitive Renewable Energy Zone (Texas)
CWC	Central Water Commission (India)
DG ENER	Directorate-General for Energy (European Commission)
EDF	Électricité de France
FERC	Federal Energy Regulatory Commission (U.S.)
EIS	Environmental Impact Statement
EA	Environmental Assessment
EE	energy efficiency
EIA	U.S. Energy Information Administration
EPA	U.S. Environmental Protection Agency
ERCOT	Electric Reliability Council of Texas
EWN	Energy-Water Nexus
GHG	greenhouse gases
GW/GWh	gigawatt/gigawatt hours
IEA	International Energy Agency
IGCC	Integrated Gas Combined Cycle
kW/kWh	kilowatt/kilowatt hour
LBNL	Lawrence Berkeley National Laboratory
MMBtu	million BTUs (British Thermal Unit)
MW/MWh	megawatt/megawatt hours
NEPA	National Environmental Policy Act (U.S.)
NOx	nitrogen oxides
NRDC	Natural Resources Defense Council
O&M	operations and maintenance
OECD	Organization for Economic Cooperation and Development

PARIS21	Partnership in Statistics for Development in the 21 <sup>st</sup> Century
PM	particulate matter
PUC	Public Utility Commission
PV	Photovoltaic
R&D	research and development
RAP	Regulatory Assistance Project
RE	renewable energy
RPS	Renewable Portfolio Standard
SGCC	State Grid Corporation of China
tcf	trillion cubic feet
TW/TWh	terawatt/terawatt hours
UNDP	United Nations Development Programme
UNEP	United Nations Environment Programme
USGS	U.S. Geological Survey

## Water use in the power sector

Most electricity is produced by thermal generators, in which water is heated into steam by burning coal or natural gas, or by nuclear fission, which turns a turbine to produce power. Cooling to remove waste-heat lost through the inherent inefficiency in the system is a very water-intensive process and is the primary focus of this report. Dependable access to water resources for cooling purposes is of paramount importance to ensuring generation reliability and safety. Reliability can be impacted by water resource constraints in two primary ways: first, water resources may not be available in adequate quantities at low enough temperatures for cooling, which is essential to safe operation. And second, hot water from the cooling process may be restricted from discharge into the environment when the temperature of the receiving water surpasses an established threshold. In either of these cases, power plants may be forced to limit operations or shut down altogether.

There are two ways that cooling systems for power plants use water and effect water resources: withdrawal and consumption. These terms are defined by the U.S. Geological Survey:

**Withdrawal:** “Water removed from the ground or diverted from a surface-water source for use.”<sup>2</sup> For thermal generation cooling purposes, withdrawn water is used to absorb waste heat and is then discharged back into the environment. In 2005, 41 percent of all freshwater withdrawals in the U.S. were for thermoelectric cooling, larger than any other sector including agriculture.<sup>3</sup>

**Consumption:** “The part [portion] of water withdrawn that is evaporated, transpired...or otherwise removed from the immediate water environment.”<sup>4</sup>

Thermal power plants employ one of the following three types of cooling systems, with very different implications for water withdrawal and consumption:<sup>5</sup>

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<sup>2</sup> J.F. Kenny, N.L. Barber, S.S. Hutson, K.S. Linsey, J.K. Lovelace, and M.A. Maupin, *Estimated Use of Water in the United States in 2005*. Circular 1344 (Reston, VA: U.S. Geological Survey, 2009), p. 38.

<sup>3</sup> *Ibid.*, p. 1.

<sup>4</sup> *Ibid.*, p. 47.

<sup>5</sup> See Electric Power Research Institute, *Water & Sustainability*, vol.1, *Research Plan* (Palo Alto, CA: Electric Power Research Institute, 2002), Section 2-12.

**Once-through, or open-loop** systems withdraw water from a source, circulate it to absorb heat, and then return it to the surface body.<sup>6</sup> These systems withdraw significantly more water than recirculating systems described below—between 10 and 100 times as much per unit of generation—but consume significantly less. During this process a fraction of water withdrawals are consumed and lost to evaporation.<sup>7</sup>

**Recirculating, closed-loop, or tower** systems withdraw water and then recycle it within the power system rather than discharging it.<sup>8</sup> These systems withdraw less water but consume at least twice as much as open-loop systems.<sup>9</sup>

**Dry cooling systems** use air flows to remove heat. Dry cooling systems have a higher parasitic load from the need to use enormous cooling fans to move large volumes of air; they are more expensive than either once-through or recirculating systems.<sup>10</sup>

Table 1 provides a comparison of withdrawal and consumption numbers by fuel and cooling type in cubic meters per megawatt-hours (m<sup>3</sup>/MWh). For any fuel, once-through cooling systems withdraw much more water than recirculating systems, making them more vulnerable to drought. For all fuels, dry cooling requires no water. For any cooling system, nuclear uses the most water, coal the next highest amount, and natural gas the least. This is due to the relative efficiencies of the plant type to convert fuel to steam. Since gas plants have the highest efficiency, they have much less waste heat to reject thus require less water. Wind and solar photovoltaic do not require cooling, though PV does use some water for washing.

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<sup>6</sup> Ibid.

<sup>7</sup> J. Macknick, R. Newmark, G. Heath, and K.C. Hallett, *A Review of Operational Water Consumption and Withdrawal Factors for Electricity Generating Technologies*. Technical Report NREL/TP-6A20-50900 (Golden, CO: National Renewable Energy Laboratory, March 2011), pp. 3, 5.

<sup>8</sup> Ibid.

<sup>9</sup> See Macknick et al., *A Review of Operational Water Consumption and Withdrawal Factors*, p. 5.

<sup>10</sup> Ibid., p. 508; Erik Mielke, Laura Diaz Anandon, and Venkatesh Narayanamurti, *Water Consumption of Energy Resource Extraction, Processing, and Conversion*. Energy Technology Innovation Policy Discussion Paper Series #2010-15 (Cambridge, MA: Belfer Center for Science and International Affairs, 2010), p. 32.

Table 1. Median withdrawal and consumption values by fuel type and cooling technology

Fuel	Cooling Type	Median Withdrawal (cubic meters <sup>11</sup> /MWh)	Median Consumption (cubic meters/MWh)
Nuclear	Tower (Recirculating)	4.2	2.5
	Once-through	167.9	1.0
Natural Gas <sup>12</sup>	Tower	1.0	0.7
	Once-through	43.1	0.4
Coal <sup>13</sup>	Tower	2.3	1.9
	Once-through	85.5	0.4
Coal w/CCS	Tower	4.3	3.2
Solar			
Photovoltaic	n/a	0.1	0.1
Wind	n/a	0.0	0.0

*Source:* Data from J. Macknick, R. Newmark, G. Heath, and K.C. Hallett, *A Review of Operational Water Consumption and Withdrawal Factors for Electricity Generating Technologies*. Technical Report NREL/TP-6A20-50900 (Golden, CO: National Renewable Energy Laboratory, March 2011).

### Water conservation, air pollution and carbon dioxide emissions

Synergies exist for some options in the power sector to meet growing electricity demand in cost-effective ways that conserve water, reduce conventional air pollutants, and cut greenhouse gas emissions (GHGs). Table 2 shows cost and environmental performance data for a selection of options to provide supply or cut demand. The least expensive option is to slow demand growth through end-use energy efficiency improvements. Not only is efficiency the cheapest approach because it avoids the need for new capacity altogether, but it also eliminates cooling water needs and emissions.

The least expensive option for new generation capacity is natural gas, which has significant environmental benefits over coal, which is the dominant fuel for power production globally. Water withdrawals and consumption are less than half that of coal for the same cooling technology, while there are no emissions of particulate matter (PM) and sulfur dioxide (SO<sub>2</sub>), 90 percent lower nitrous oxide emissions (NO<sub>x</sub>), and carbon dioxide emissions that are also less than half that of coal.

<sup>11</sup> One cubic meter is equal to 264 gallons of water.

<sup>12</sup> Natural gas combined cycle (NGCC).

<sup>13</sup> Supercritical/advanced coal.

Table 2. Synergies exist between water conservation, cost, and environmental performance

	Withdrawal	Consumption	Cost <sup>14</sup>	PM	SO <sub>2</sub>	NO <sub>x</sub>	CO <sub>2</sub>
	m <sup>3</sup> /MWh <sup>15</sup>		\$/MWh	kg/MWh			
Coal	2.3	1.9	96	0.06	0.32	0.26	761
Coal w/CCS	4.3	3.2	122 <sup>16</sup>	0.05	-	0.33	92
NGCC	1.0	0.7	66	-	-	0.03	359
Nuclear	4.2	2.5	96	-	-	-	-
Wind	-	-	80 <sup>17</sup>	-	-	-	-
PV	0.1	0.1	130	-	-	-	-
Energy efficiency	-	-	0-50	-	-	-	-

Source:

Macknick et al., 2011; EIA, “Levelized Cost and Levelized Avoided Cost of New Generation Resources in the Annual Energy Outlook 2014,” April 2014; NETL, Bituminous Performance Tool,

[http://www.alrc.doe.gov/energy-analyses/pubs/Bituminous\\_Performance\\_Tool\\_Rev6.swf](http://www.alrc.doe.gov/energy-analyses/pubs/Bituminous_Performance_Tool_Rev6.swf)

Unsubsidized wind power costs in high-quality resource areas are currently lower than coal or nuclear and they are continuing to drop as the technology continues to improve.<sup>18</sup> Wind does not require any cooling water and does not release any emissions. Solar PV also has very positive environmental performance, though the costs are currently high. PV costs are coming down, however, with a 60 percent average price drop between 2011 and the end of 2013.<sup>19</sup>

For two key technologies to reduce GHGs, Nuclear and carbon capture and sequestration (CCS), there are water penalties as opposed to savings. Due to nuclear’s lower efficiency and lack of heat loss through smokestacks, and CCS’s parasitic loads, these both have considerably higher cooling water requirements. Dry cooling is not currently used for nuclear for safety reasons and has not been demonstrated for coal with CCS.

<sup>14</sup> Total system levelized cost of energy.

<sup>15</sup> Assumes tower/recirculating cooling.

<sup>16</sup> Derived from EIA (2014) based on difference between IGCC and IGCC with carbon capture and sequestration (CCS).

<sup>17</sup> Wind and PV costs are unsubsidized.

<sup>18</sup> Department of Energy. “2012 Wind Technologies Report.” August 2013. [http://www1.eere.energy.gov/wind/pdfs/2012\\_wind\\_technologies\\_market\\_report.pdf](http://www1.eere.energy.gov/wind/pdfs/2012_wind_technologies_market_report.pdf)

<sup>19</sup> Solar Energy Industries Association. “Solar Energy Facts: 2013 Year In Review.” <http://www.seia.org/sites/default/files/YIR%202013%20SMI%20Fact%20Sheet.pdf>

## Electricity-water modeling

Our purpose in building and applying a new model for this project is to get a better understanding of water use in the four case studies and of some technology and policy options available or under consideration. The model and results are scoping tools. We intend the results to be broad indicators, and we are concerned with significant changes in direction and scale rather than granular changes.

The Electricity-Water Nexus model is a mixed-integer linear programming model that seeks to find the optimal solution to meet power demand at least cost. The model simulates new construction, retirement due to aging, and early retirements due to cost-ineffectiveness.

We constructed the model to meet power demand for each year of the simulation by choosing from a set of representative power plants that include six options for fuel—three thermal (coal, natural gas, and nuclear) and three renewable (hydro, wind, and PV), four combustion options for coal (conventional or sub-critical and advanced or super-critical, each without and with carbon dioxide capture and sequestration, or CCS), four combustion options for gas (conventional and combined cycle, each without and with CCS), and three cooling options for the thermal plants (once-through, recirculating, and dry). The starting power plant options and numbers for each case study were determined by the existing fleet in each region.

For each representative power plant, we defined a set of characteristics for cost, generation, and environmental performance. These characteristics include fixed and variable costs; generation capacity; capacity factor (the percent of time the plant can run); water withdrawal and consumption; and emissions of nitrogen oxides (NO<sub>x</sub>), mercury, sulfur dioxide (SO<sub>2</sub>), particulate matter (PM), and carbon dioxide (CO<sub>2</sub>). Fixed costs include amortized capital costs and fixed operating costs. Variable costs include variable operation and maintenance costs including fuel, and transmission costs. Demand projections come from official published sources, case-by-case. Cost data come from the Energy Information Administration (EIA), water withdrawal and consumption data come from the National Renewable Energy Laboratory (NREL), and environmental data come from the National Energy Technology Laboratory (NETL). Assumptions about the future costs and performance of renewable power come from a variety of sources, including NREL. Further documentation of the model is provided in the appendix.

The model was developed by CNA and reviewed by staff from the Regulatory Assistance Project (RAP) and Synapse Energy Economics. These reviewers also helped us to develop the scenarios for each case study. For each case, we developed a baseline that is a reproduction of a projection from some other published source(s). The baseline defines the annual demand, the fuel mix and how it changes over time, the starting fleet of power plants, and the starting policy conditions. The baseline gives us an initial point of comparison and a jumping-off point to develop other scenarios.

# China

## Introduction

China is the world's most substantial energy consumer and is experiencing rapid economic growth. The figures are staggering; China is the largest primary energy consumer in the world by a wide margin, consumes the largest amount of coal in the world (at half of total global consumption), and is the world's largest emitter of greenhouse gases.<sup>20</sup> Over the past ten years, 70 million new jobs emerged in the Chinese economy, and the country now leads the world in many markets, including automobiles, steel, cement, glass, and infrastructure markets including housing, power plants, renewable energy, highways, rail systems, and airports.<sup>21</sup> Analysts from the Organization for Economic Cooperation and Development (OECD) estimated in 2012 that the nation's GDP will surpass the U.S. and become world's largest economy before 2020.<sup>22</sup> Fueling this burgeoning economic growth are similar rises in energy production and consumption; primary energy consumption in China grew a staggering 255 percent between 2002 and 2012, and installed capacity rose 304 percent from 2000 to 2010.<sup>23</sup>

Energizing a population of this scale requires robust electricity transmission and generation infrastructure. With a size termed "mind boggling" the State Grid Corporation of China (SGCC) is the world's largest utility, and is responsible for delivering power to approximately 88 percent of China, an area with 286 million customers and a population of over 1 billion.<sup>24</sup> The SGCC is divided into five regional power grid companies, the North Grid, the Northeast Grid, the Northwest Grid, the East Grid, and the Central Grid, with each grid containing provincial electric power

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<sup>20</sup> Consuming 24 percent more than the U.S., though considerably less per capita. See *BP Statistical Review of World Energy 2013* (London: BP Plc, June 2013), p. 5.

<sup>21</sup> Keith Schneider, Jennifer L. Turner, Aaron Jaffe, and Nadya Ivanova, "Choke Point China: Confronting Water Scarcity and Energy Demand in the World's Largest Country," *Vermont Journal of Environmental Law* 12 (2011): 713-734.

<sup>22</sup> Organization for Economic Cooperation and Development, *Looking to 2060: Long-Term Global Growth Prospects*. OECD Economic Policy Papers, No. 03 (Paris: OECD, November 2012), p. 22.

<sup>23</sup> BP Statistical Review of World Energy 2013.

<sup>24</sup> *China: State Grid Corporation of China Profile* (Austin, TX: Zpryme Research & Consulting, March 2012).

companies.<sup>25</sup> Within each grid are numerous generation facilities deriving energy from various fuels, and the SGCC manages intra- and interregional flows of electricity to promote regional reliability and reduces transmission line loss.

## Case study selection

The focus of our China case study is collectively the North Grid, Northeast Grid, and Northwest Grid. These regions, highlighted in figure 1, include the municipalities of Beijing and Tianjin, as well as the provinces of Hebei, Shanxi, Shandong, and parts of Inner Mongolia. According to the most recently available data, the North China Grid Company Limited generated about 1.2 million GWh in 2011 from its total capacity of nearly 250 GW. This represents more than 40 percent of China's total power generation.

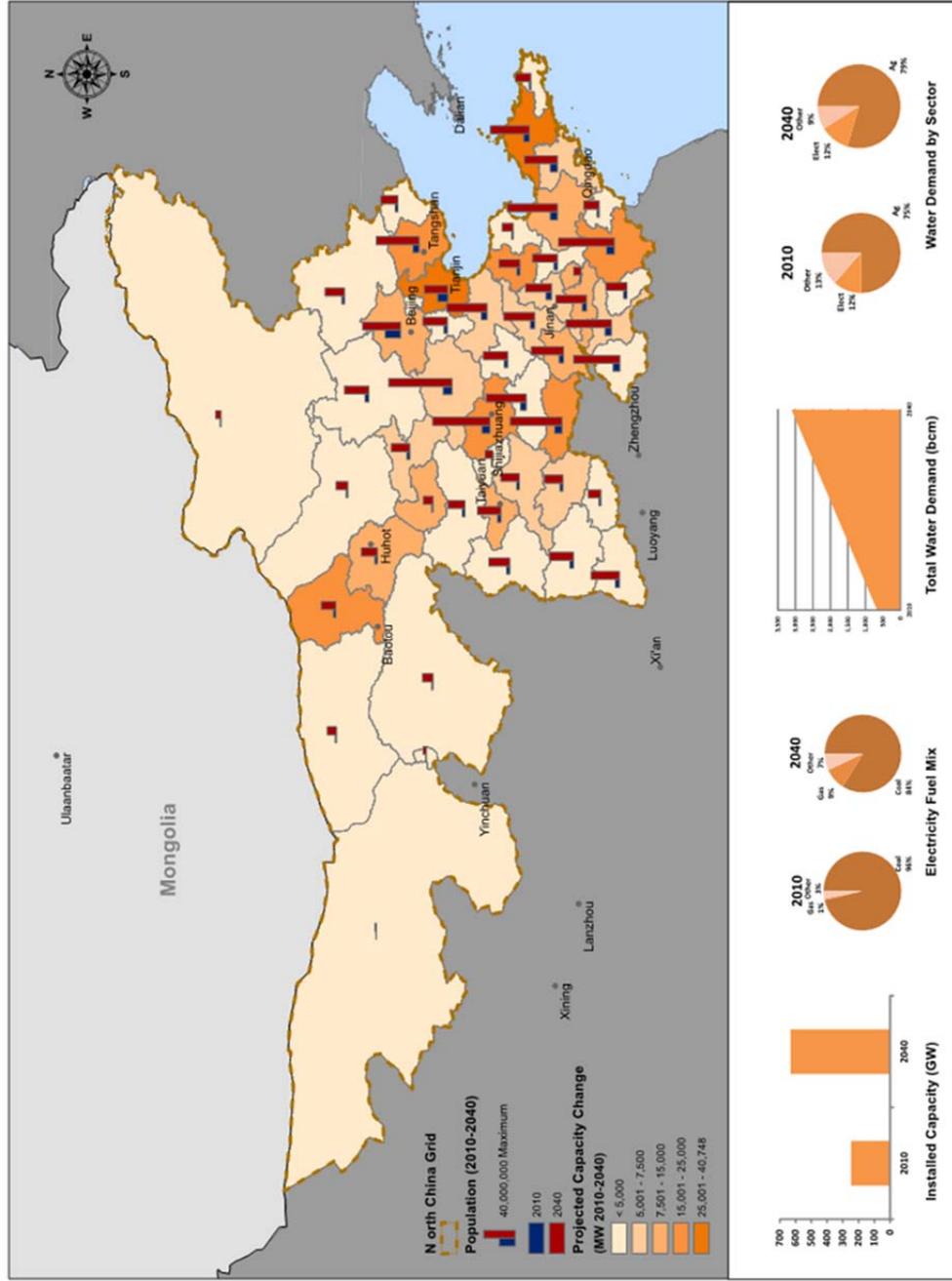
We selected the China North Grid as one of our case studies based on its

1. large size;
2. growth in electricity demand;
3. significant dependence on coal generation; and
4. sensitivity to future water crises.

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<sup>25</sup> State Grid Corporation of China, <http://www.sgcc.com.cn/ywlm/gsgk-e/zzjg-e/zzjg-e1.shtml>.

Figure 1. China North Grid Projected Population Growth and Capacity Change by Province, 2010–2040



First, in terms of size, the North China Grid is one of the largest electric utilities in the country, serving a population of nearly 250 million people. This number has been experiencing a steady increase, driven by a stream of Chinese relocating from rural to urban centers in search of improved living conditions and employment; growth is especially robust in the textile, agriculture, and heavy industry sectors (such as mining, refining, and power generation) in the Hebei, Shanxi, and Shandong provinces. Often threatened by environmental and water resources constraints, the Chinese government wants the trend toward urbanization and strong economic development to continue; official government proclamations call for a doubling of the size of the Chinese economy from 2010 to 2020 and anticipate the urbanization of another 350 million people between 2010 to 2030.<sup>26</sup> As this growth continues to strain already limited water resources in a number of regions, significant investment in energy efficiency (EE) and demand response, renewable energy (RE), and a trajectory directed away from the expansion of thermal power generation will be required.

Second, demand for electricity is expected to grow dramatically in the North China Grid. Its total generation assets, inclusive of all providers, amounted to approximately 247 GW in 2009 but are expected to more than double to 631 GW by 2040, with most of that growth concentrated in Shanxi, Shandong, and Tianjin Provinces. This rapid growth does not appear to be unique to the North China Grid; the IEA projects a near tripling of China's 2010 domestic electricity generation by 2040.<sup>27</sup> Indeed, for China as a whole, the EIA expects rapid economic growth to lead to growth in installed capacity from 1,073 gigawatts in 2011 to 2,265 by 2040.<sup>28</sup> This high growth in installed capacity is a further reflection of rapid demand-side growth, the coupling of which has resulted in frequent shortages of electricity and blackouts throughout the nation, a liability only worsened by water resource concerns. In the North China Grid, 12 provinces, municipalities, and autonomies had to implement rolling blackouts in 2002, a number that rose to 22 in 2003, 24 in 2004, and 26 in 2005.<sup>29</sup>

Third, practically all of the capacity in the North China Grid (96 percent) is coal-fired. The region is home to a majority of the country's coal production, with just two provinces accounting for almost half of China's total coal production. Rather than make the region less dependent on coal, the 12<sup>th</sup> Guideline (2011–2015) explicitly aims to increase rates of coal extraction.<sup>30</sup> Production of coal nationwide has already tripled

<sup>26</sup> Schneider et al., "Choke Point China."

<sup>27</sup> U.S. Energy Information Administration, "China," <http://www.eia.gov/countries/cab.cfm?fips=CH>.

<sup>28</sup> Ibid.

<sup>29</sup> Chun Chun Ni, *China's Electric Power Industry and Its Trends* (Tokyo: Institute of Energy Economics, April 2006).

<sup>30</sup> "Leading the Charge," Energy Global, March 10, 2012, [http://www.energyglobal.com/news/coal/articles/China\\_coal\\_mining\\_industry\\_prepares\\_f](http://www.energyglobal.com/news/coal/articles/China_coal_mining_industry_prepares_f)

from 2000 to 2010, and government projections suggest that China will need to add another billion tons of coal production annually by 2020, an increase of 30 percent.<sup>31</sup>

Fourth, in terms of water, China is the second largest water irrigator by volume (after the U.S.), and surface and groundwater resources surrounding cities have diminished as a result of heavy use by the agricultural sector. Much of China's existing water resources are also heavily polluted; approximately 30 percent of river water is considered unfit for agricultural or even industrial use.<sup>32</sup> Natural disruptions and changes in precipitation patterns, increasingly a threat due to climate change, have also played a large role in driving EWN risk exposure in China. A drought in August 2009 left 5 million people and 4.1 million livestock without drinking water, and it destroyed 8.7 million hectares of crop land, only to be followed by a rare winter drought in 2009 impacting 10 million hectares and leaving 4 million people and 2 million livestock without adequate water.<sup>33</sup> A 2012 study led by the Chinese Academy of Sciences, the Chinese Academy of Agricultural Sciences, and a team of international researchers concluded that "China faces its own 'perfect storm' as rapid economic transition drives increasing per capita demand for water, food, and energy, with far reaching environmental consequences."<sup>34</sup>

## Modeling analysis of power generation scenarios for China's North Grid: 2010–2040

To estimate and visualize where various energy paths may lead the China North Grid in the future, we modeled six scenarios briefly described below, and more thoroughly later in this section.

### China North Grid Scenarios

1. The Baseline scenario is founded on the existing fuel mix of the China North Grid regions and assumes a high degree of dependence on coal throughout the scenario,

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[or\\_a\\_strong\\_future.aspx](#). Note that the "Guideline" was formerly known as the "Five-Year Plan."

<sup>31</sup> Schneider et al., "Choke Point China."

<sup>32</sup> Lucy Carmody, Dave Doré, Guo Peiyuan, Anna-Sterre Nette, and Jiali An, *Water in China: Issues for Responsible Investors* (Singapore: Responsible Research Plc Ltd, February 2010).

<sup>33</sup> Ibid.

<sup>34</sup> Jinxia Wang, Sabrina G.S.A. Rothausen, Declan Conway, Lijuan Zhang, Wei Xiong, Ian P. Holman, and Yumin Li, "China's Water-Energy Nexus: Greenhouse-Gas Emissions from Groundwater Use for Agriculture," *Environmental Research Letters* 7, no. 1 (March 2012): 014035.

with an increase in wind to 15 percent of generation and holding at that share for the rest of the simulation, as well as a small amount of gas.

2. **Fixed water availability (WaterLimit):** The WaterLimit scenario limits water consumption to the amount calculated by the model for the baseline in 2010. The model must meet the same demand as the Baseline but without any additional water.
3. **High end-use efficiency (High-EE):** The High EE scenario assumes a decline of 1 percent/year in demand from the baseline (i.e., reduction in the growth rate from 5 percent a year to 4 percent).
4. **CO2CAP 1:** The model must meet the same demand as the Baseline without exceeding a carbon dioxide cap that is based on meeting a global 450 parts per million (ppm) carbon concentration ceiling described by the International Energy Agency.<sup>35</sup> In this scenario we assume that the carbon cap is achieved through carbon dioxide capture and sequestration (CCS) and wind.
5. **CO2CAP 2:** This scenario is the same as CO2CAP 1, but carbon reductions are achieved through the availability of cheap natural gas supported by utilization of unconventional gas resources, and with wind.
6. **Coal Cap 20%:** The Coal Cap 20% scenario places a cap on coal generation that is 20 percent greater than the 2010 value. The model must still meet the Baseline demand projections.

## China North Grid fuel mix by scenario

### Baseline scenario

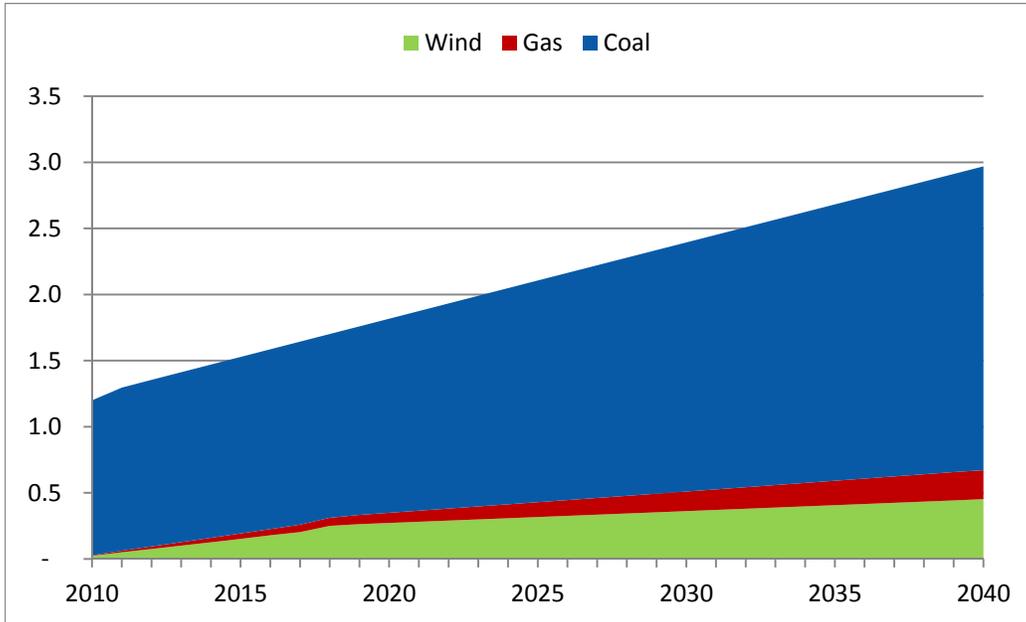
The fuel mix for the baseline scenario is shown in figure 2. At the start, the North grid is dependent on coal for 97 percent of generation, split between conventional subcritical coal with once-through cooling and advanced supercritical coal with recirculating cooling technologies (split is not shown). Nationally, roughly 40 percent of coal generation uses once-through cooling, about 50 percent is recirculating cooling, and the remainder is dry cooling. Wind power is under 2 percent and gas is less than 1 percent. In the Baseline scenario, new plants are constrained from use of once-through cooling. Because dry cooling is modeled as 10 percent more expensive, recirculating cooling dominates and dry cooling remains a small share. Due to the North Grid's strong wind resources, it is likely that wind will be the most competitive renewable energy resource in the North Grid region, and we have chosen to model wind exclusively as the renewable energy resource.

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<sup>35</sup> International Energy Agency, *World Energy Outlook 2012*.

By 2040, coal is under 78 percent of the mix and gas is about 7 percent. The kink in 2018 is where wind generation hits the 15 percent generation goal; it stays at that share for the remainder of the run. Total demand in the Baseline grows from about 1.2 million GWh per year to almost 3 million GWh per year, an increase of nearly 150 percent. Total generating capacity grows from almost 250 GW to a bit over 700 GW.

Figure 2. Baseline fuel mix for China's North Grid



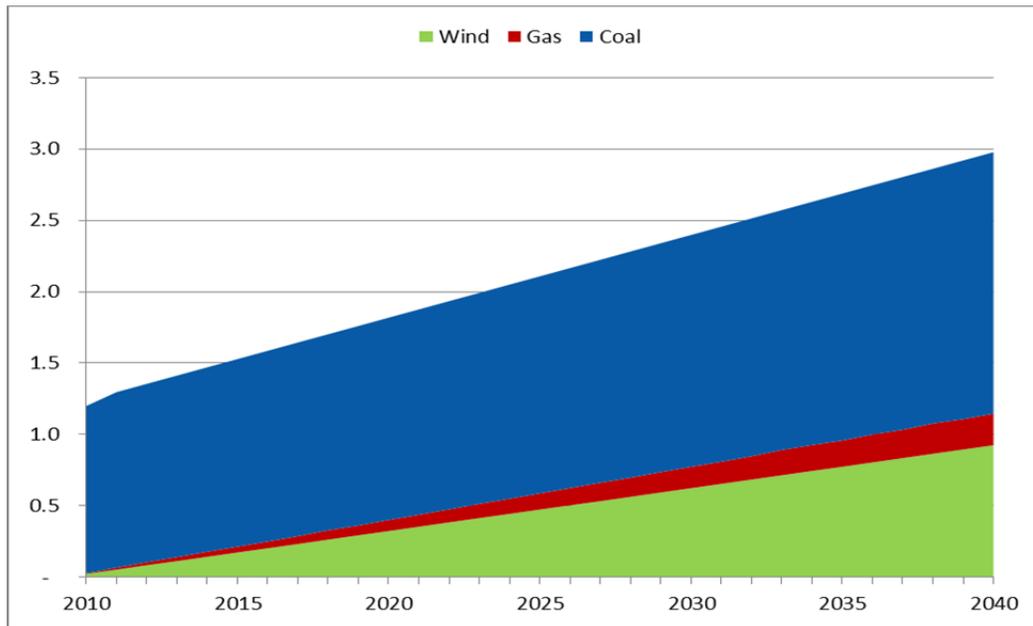
Units = million GWh/year

## Fixed water availability scenario (WaterLimit)

The fixed water availability scenario shown in figure 3 assumes that there is no more water available for the power sector than we calculate is consumed for the 2010 Baseline, approximately 1.5 bcm/year. There are two principal changes in this scenario relative to the Baseline: considerable wind resources are added, and coal plants shift to a much higher degree of dry cooling—about half utilize dry cooling by the end of the simulation, when new builds are dominated by dry cooling. More than 30 percent wind by 2040 represents an enormous amount of wind capacity—over 300 GW total—added at up to 10 GW/year. We allowed large amounts of wind to

come into the solution because the area around the North Grid has exceptional wind resources.<sup>36</sup>

Figure 3. WaterLimit power generation fuel mix



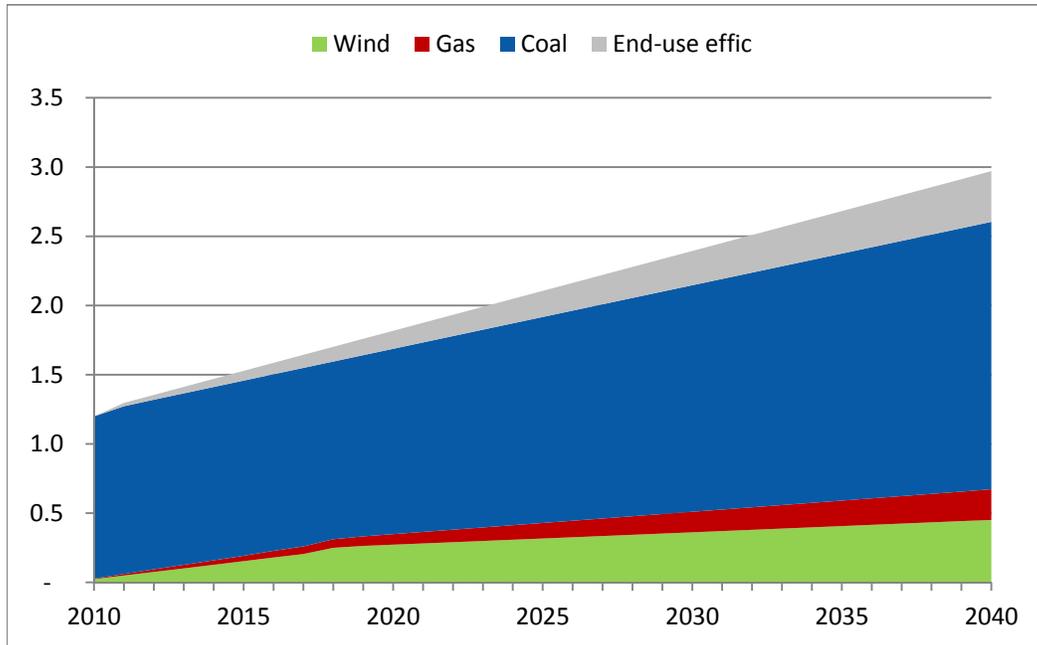
Units = million GWh/year

### *High end-use EE scenario (High-EE)*

In the high end-use efficiency scenario shown in figure 4, we assumed a 1 percentage point reduction in the annual growth rate for electricity demand—from 5 to 4 percent—producing a 12 percent (or 370,000 GWh) drop in annual demand (compared to the Baseline) by the end of the simulation period. Due to reduced demand there is also a similar drop in capacity, resulting in cost savings even when the cost of efficiency gains is included. Similarly, water use, CO<sub>2</sub>, and SO<sub>2</sub> emissions are much lower for this scenario, as shown in Section 2.4.5.

<sup>36</sup> International Energy Agency and Energy Research Institute, *Technology Roadmap: China Wind Energy Development Roadmap 2050* (Paris: OECD/International Energy Agency), p. 14, [https://www.iea.org/publications/freepublications/publication/china\\_wind.pdf](https://www.iea.org/publications/freepublications/publication/china_wind.pdf).

Figure 4. High Energy Efficiency power generation fuel mix



Units = million GWh/year

### *CO<sub>2</sub>Cap 1 and CO<sub>2</sub>Cap 2 scenarios*

We tested two scenarios to cap CO<sub>2</sub> emissions, the first (CO<sub>2</sub>CAP 1) is based on the implementation of CCS technologies<sup>37</sup> for coal, and the second (CO<sub>2</sub>CAP 2) depends on substituting natural gas for coal. Both scenarios also rely heavily on the same amount of wind generation. The concept here was to compare two prominent options of reducing carbon dioxide emissions from the power sector for their relative impacts on water resources.

For both scenarios we set a 450ppm CO<sub>2</sub> cap as utilized in the IEA's *World Energy Outlook 2012*. IEA developed a cap that assumes global CO<sub>2</sub> emissions will not exceed 450 ppm. To do this, their cap allows 20 percent growth from 2010 to 2020. From 2020 to 2030 the cap declines back to the starting value, and then from 2030 to 2040 emissions are cut by 20 percent.

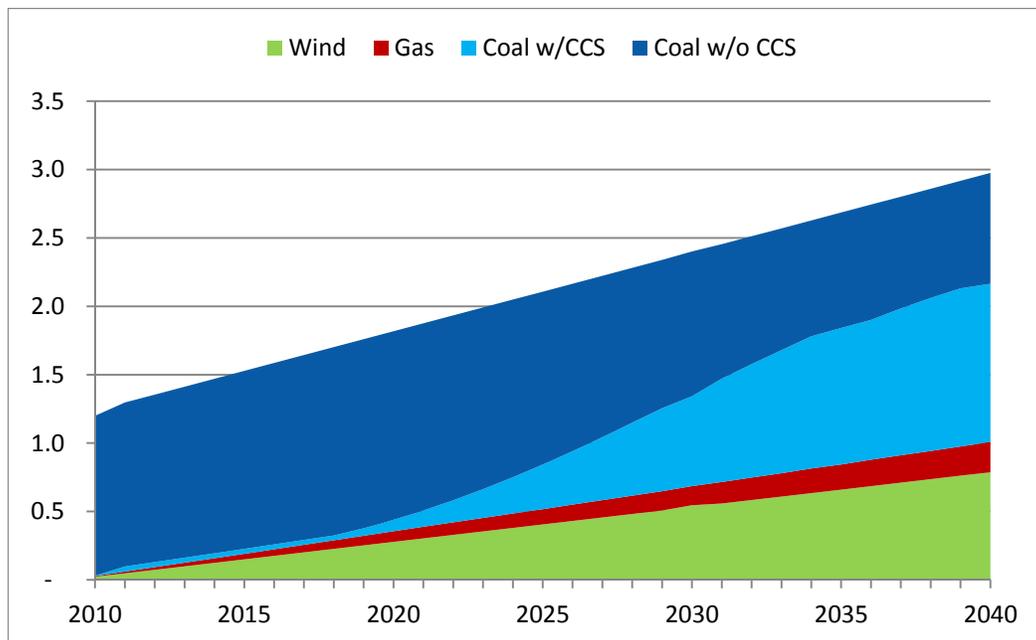
CCS technologies are drawing quite a bit of attention and R&D funding. In the context of water, however, CCS has a significant downside in that it can increase water

<sup>37</sup> For a detailed description of CCS technologies, see U.S. Environmental Protection Agency, "Carbon Dioxide Capture and Sequestration," n.d., <http://www.epa.gov/climatechange/ccs/index.html>.

consumption and withdrawal by 100 percent for pulverized coal plants, both super- and subcritical (see Section 2.4.3).<sup>38</sup>

Figure 5 shows the fuel mix for the first carbon cap scenario, which employs CCS technology for coal. Very little CCS is built between 2010 and 2020, but after that, coal generation using CCS grows rapidly due to the cap, making up about 60 percent of all coal generation by the end of the run. Total coal generation still constitutes two-thirds of all generation. Wind generation is higher than the Baseline, making up a little over 25 percent of total generation and representing over 250 GW of wind capacity. Gas generation is equal to the Baseline level at 7 percent.

Figure 5. Fuel Mix for CO<sub>2</sub>Cap 1 met with CCS and wind



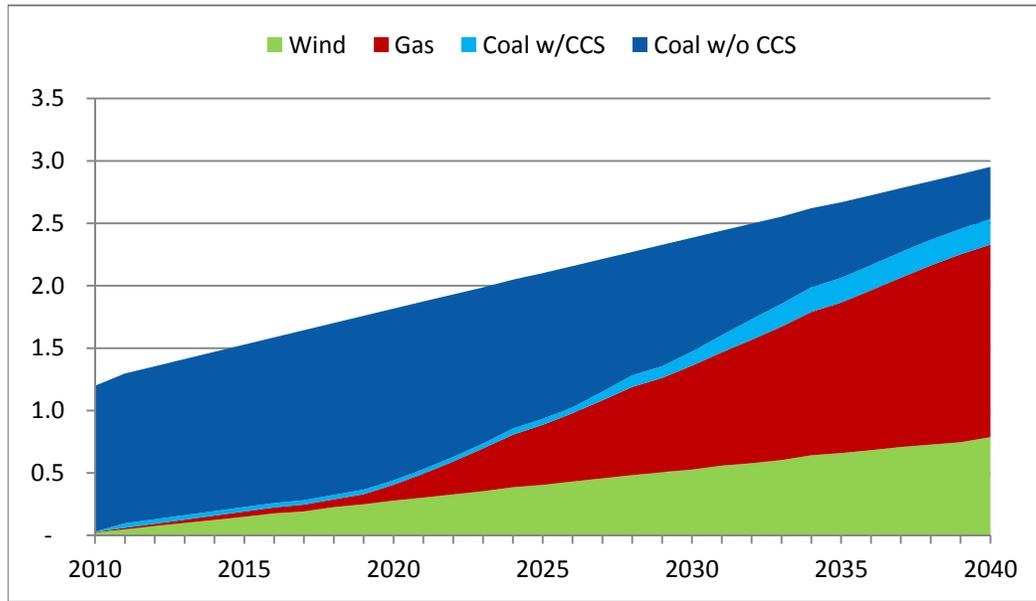
Units = million GWh/year

For the purposes of comparison we set a fixed share of wind generation for both carbon cap scenarios to isolate the differences between meeting the cap with CCS and meeting it with shale gas. The fuel mix for the shale gas scenario (CO<sub>2</sub>Cap 2) is shown below in figure 7. We assumed for this scenario that gas prices drop by 50 percent by 2025 to roughly 37 ¥/MBtu (U.S. \$6/MBtu). We see that gas generation is negligible prior to 2020, but grows rapidly after that, replacing a great deal of coal

<sup>38</sup> U.S. Department of Energy/National Energy Technology Laboratory, *Power Plant Water Usage and Loss Study* (Washington, DC: DOE-NETL, May 2007 revision).

generation. By 2040, gas generation accounts for about 47 percent of generation, and coal has dropped to 26 percent—the same as wind.

Figure 6. Fuel mix for CO<sub>2</sub>Cap 2 scenario met with shale gas and wind



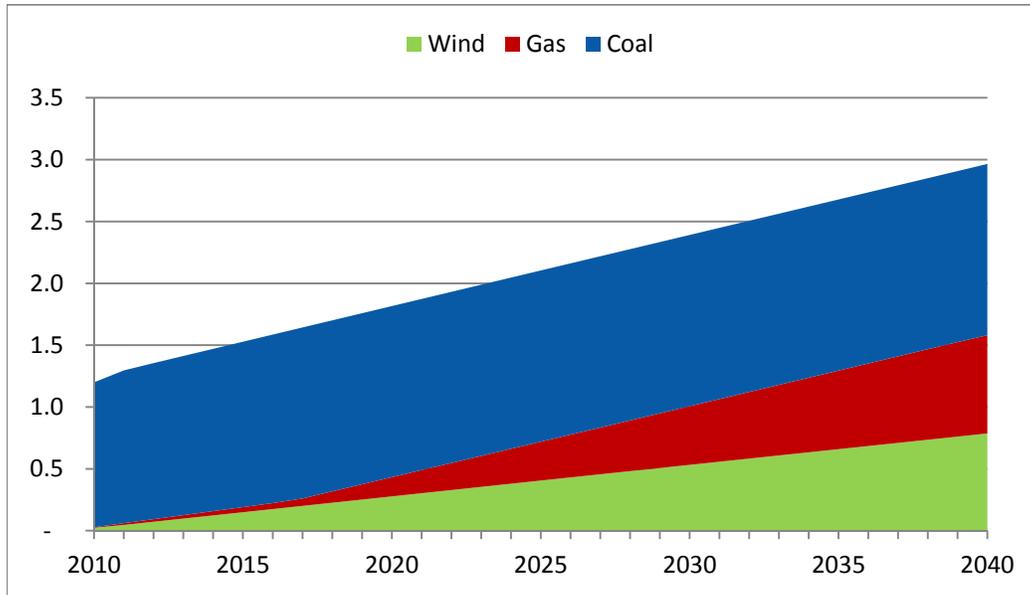
Units = million GWh/year

### *Coal Cap 20% scenario*

China is considering caps in coal generation for some regions of the country. We look at the possible impacts of this policy in our last scenario, which limits further growth in coal generation to 20 percent (figure 7). At the current demand growth rate in China's North Grid, this cap will take roughly seven years to hit. Up to this point, wind has been adding about 8 GW of new capacity a year, a very large amount. Beyond 2017, gas generation begins to grow rapidly as well to meet demand, even though in this scenario the fuel costs for gas generation were not reduced. By the end of the simulation, coal's share of the fuel mix is about 48 percent (with wind and gas splitting the remainder).

For this scenario we made a simplifying assumption that all the demand in the region must be met without imports or exports. This forces the model to build a great deal of natural gas capacity, even though in this scenario the fuel is very expensive, driving up total system costs. In reality, the region likely would import power from other regions. The scenario is nevertheless instructive in that it considers the implications of capping China's most abundant fuel.

Figure 7. Coal Cap 20% power generation fuel mix



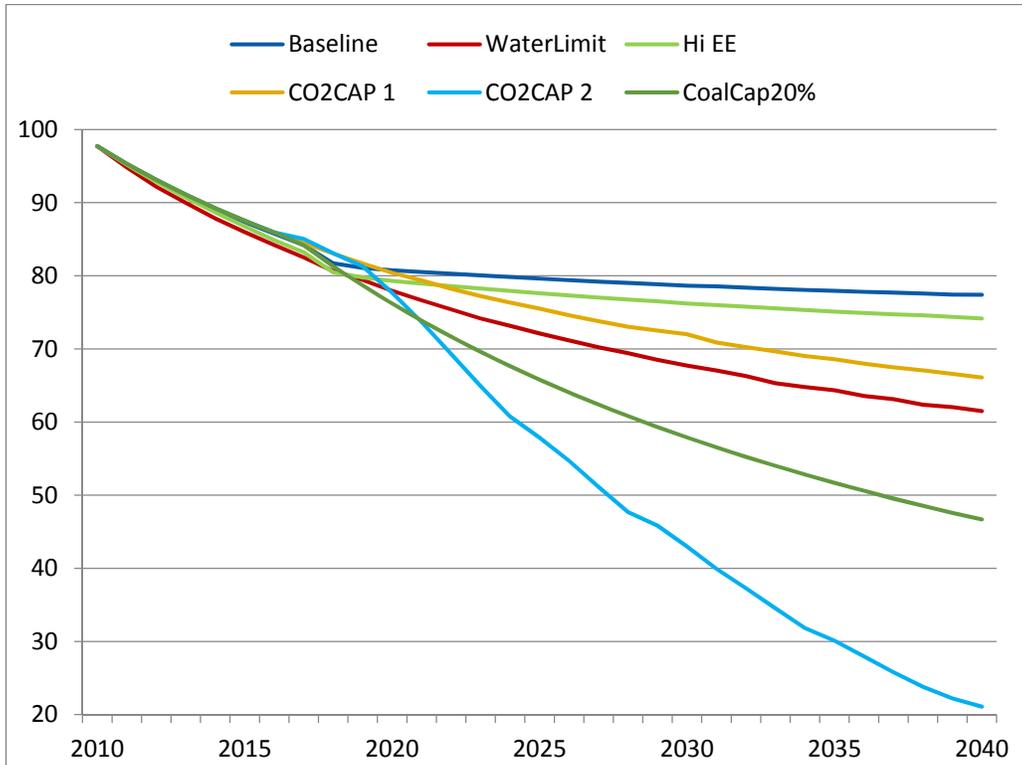
Units = million GWh/year

## Cross-scenario comparisons

### Share of coal generation

The dominant determinants of the key indicators evaluated across all cases in this report are the degree to which coal is in the fuel mix and the combustion and cooling technology used. Figure 8 displays the percentage of coal generation for each of the scenarios we tested. There is a great discrepancy across the scenarios in coal generation, spreading from 78 percent at the end year of the Baseline scenario to just 26 percent for the CO<sub>2</sub>CAP 2 scenario that is highly dependent on shale gas. The coal share for High-EE is just a bit lower than the Baseline, but with a smaller total capacity level. The WaterLimit and CO<sub>2</sub>CAP 1 scenarios show roughly the same outcome with the proportion of coal generation in the 60 percent range while the Coal Cap 20% scenario is lower at 47 percent. The lowest, at just over 20 percent, is the CO<sub>2</sub>CAP 2 scenario, which depends on shale gas substituting for coal.

Figure 8. Share of coal-based power generation by scenario

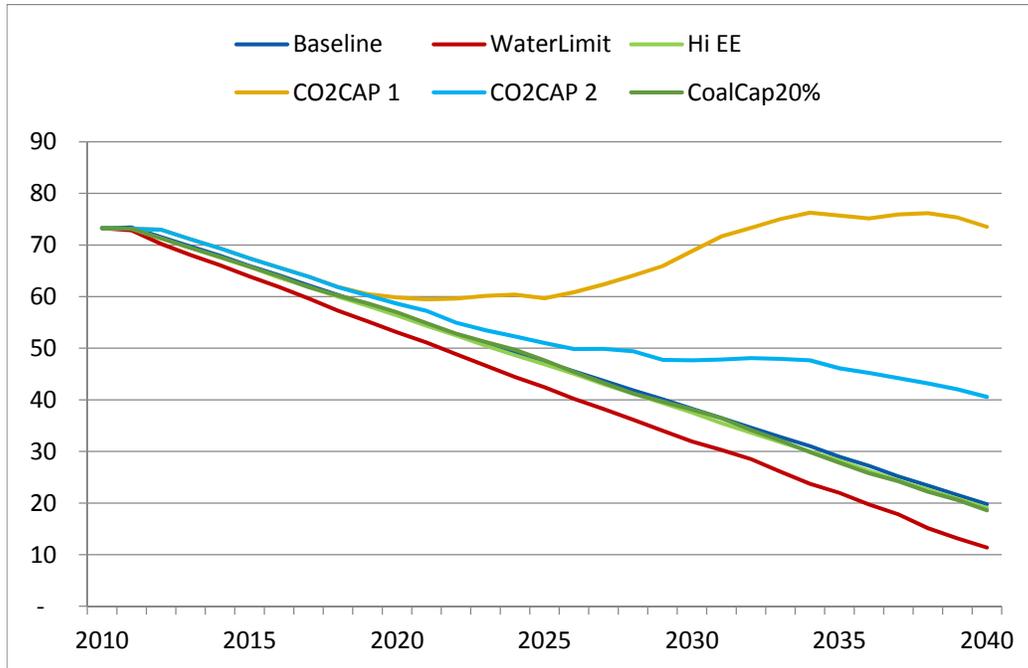


Units = Percent

## Water withdrawal

In figure 9, we present the results for water withdrawals by scenario. For the Baseline, WaterLimit, High-EE, and Coal Cap 20% scenarios, water withdrawals drop dramatically because the coal plants using once-through cooling are aging out of the fleet and being replaced by new plants that are assumed to use recirculating cooling. It's a different story for the two carbon cap scenarios, however, depending on the amount of carbon capture and sequestration implemented.

Figure 9. Water withdrawals by scenario



Units = bcm/year

## CCS and water use

The CO<sub>2</sub>CAP 1 scenario shown in figure 9 experiences significantly increased water withdrawals as compared to the other scenarios presented due to the use of CCS as the primary mechanism to achieve CO<sub>2</sub> reduction. The CO<sub>2</sub>CAP 2 scenario also withdraws much more water than the other scenarios because there is still quite a bit of CCS used, and the magnitude of the water withdrawal and consumption differential is so large with this technology.

Table 3 shows the median consumption and withdrawal values in cubic meters per megawatt-hour (m<sup>3</sup>/MWh) for thermal generators with and without CCS according to cooling technology. With some variation, CCS use significantly increases withdrawals and consumption, an effect lower for advanced coal than conventional subcritical coal but significant in all cases. Dry cooling does not appear to work with CCS at present.

Table 3. Median withdrawal and consumption values for thermal generators with and without CCS using recirculating cooling (m3/MWh)

	Carbon Capture?	Withdrawal	% Change With CCS	Consumption	% Change With CCS
Advanced Supercritical Coal	no	2.3		1.9	
	yes	4.3	+84%	3.2	+72%
Conventional Subcritical Coal	no	2.0		1.8	
	yes	4.8	+140%	3.6	+100%
Combined Cycle Gas Turbine	no	1.0		0.7	
	yes	1.9	+96%	1.4	+91%

Source:

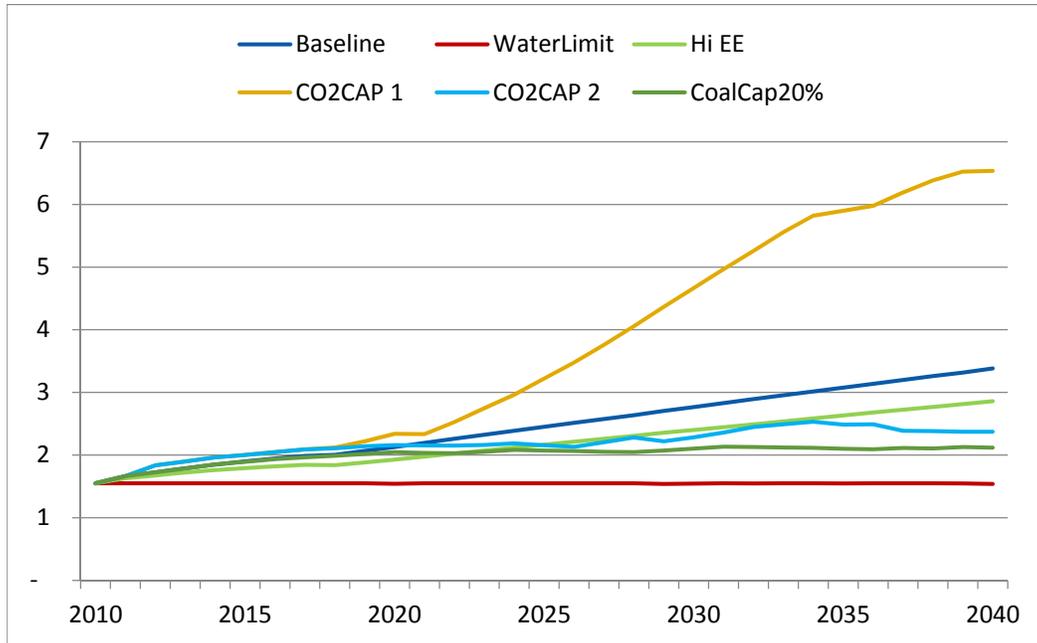
Data from J. Macknick, R. Newmark, G. Heath, and K.C. Hallett, A Review of Operational Water Consumption and Withdrawal Factors for Electricity Generating Technologies. Technical Report NREL/TP-6A20-50900 (Golden, CO: National Renewable Energy Laboratory, March 2011).

Based on this rough comparison, CCS clearly will have substantial impacts on water consumption and withdrawal where it is adopted, making it especially unlikely this technology will be employed for carbon mitigation in water scarce areas. This fact underscores both the great challenge of utilizing coal while minimizing CO<sub>2</sub> emissions and the likelihood that these emissions will be a necessary trade-off in regions that continue to construct thermal generation amidst water stress. As a result, this report recommends heavy investment into demand-side energy efficiency (EE) and supply-side RE to minimize the need for future coal thermal generation, particularly in the China North Grid regions.

### *Water consumption*

Consistent with the findings highlighted above, water consumption is extraordinarily high for the CO<sub>2</sub>CAP 1 scenario, which relies heavily on CCS for CO<sub>2</sub> mitigation purposes, reaching a consumption level almost double that of the Baseline by the end of the simulation. CO<sub>2</sub>CAP 2 uses less water than the Baseline because of its heavy reliance on natural gas generation, which consumes less than half of the amount of water consumed by coal generation as demonstrated in table 2. As expected, the WaterLimit scenario shows no growth in water consumption for the power sector, while the Baseline grows by about 120 percent during the simulation as the coal portfolio continues to expand. Coal Cap 20% is second to WaterLimit as a result of its heavy use of wind, and the High-EE scenario produces a growth rate very similar to the Baseline but slowed by a reduction in demand. A more aggressive energy efficiency scenario would have cut water consumption more.

Figure 10. Water consumption for cooling by scenario



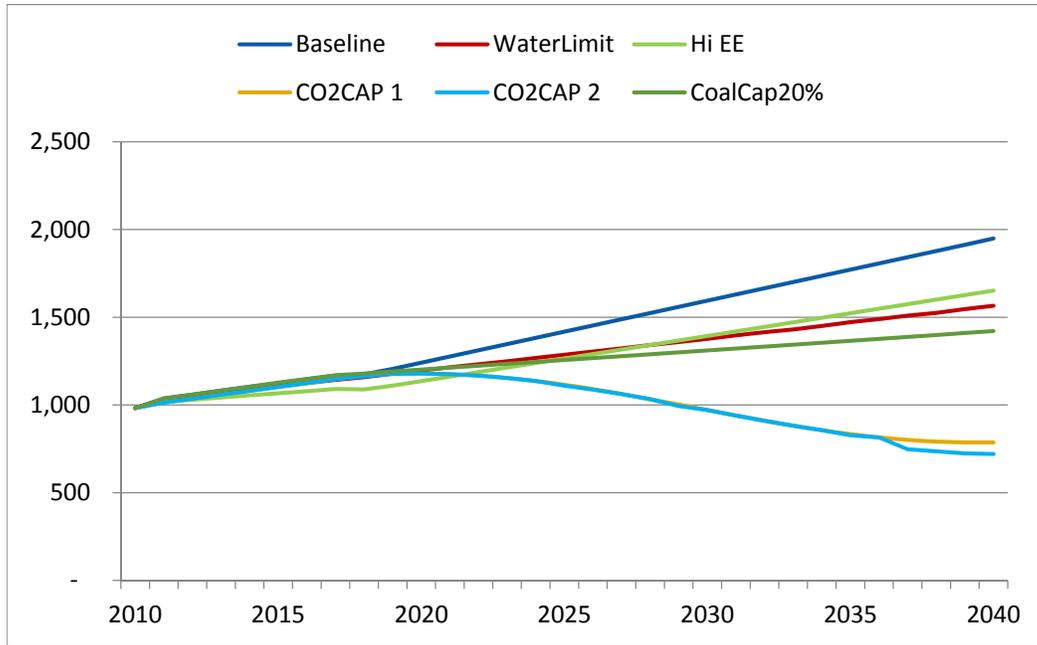
Units = bcm/year

### Emissions

CO<sub>2</sub> emissions also demonstrate a wide variance across our scenarios (figure 11). Not surprisingly, the Baseline scenario shows the highest increase, producing nearly a doubling of CO<sub>2</sub> emissions, from about 1 billion metric tons per year to just short of 2 billion by the end of the run, as increasing demand is met by a growing coal portfolio set amidst a 15 percent cap on the share of wind.

Two of our scenarios that are not specific carbon caps still provide reductions in CO<sub>2</sub> emissions while maintaining large coal portfolios. WaterLimit achieves this with wind, and High-EE achieves this with demand reduction. While these were modeled separately, it is a core recommendation of this report that these be utilized in tandem to reduce the need for a growing coal portfolio that is placing extraordinary demands on limited water resources among other major impacts. The two carbon cap tests allow emissions to grow, retreat, and then diminish according to the sine form of the 450ppm cap scenario used in the IEA's *World Energy Outlook 2012*.

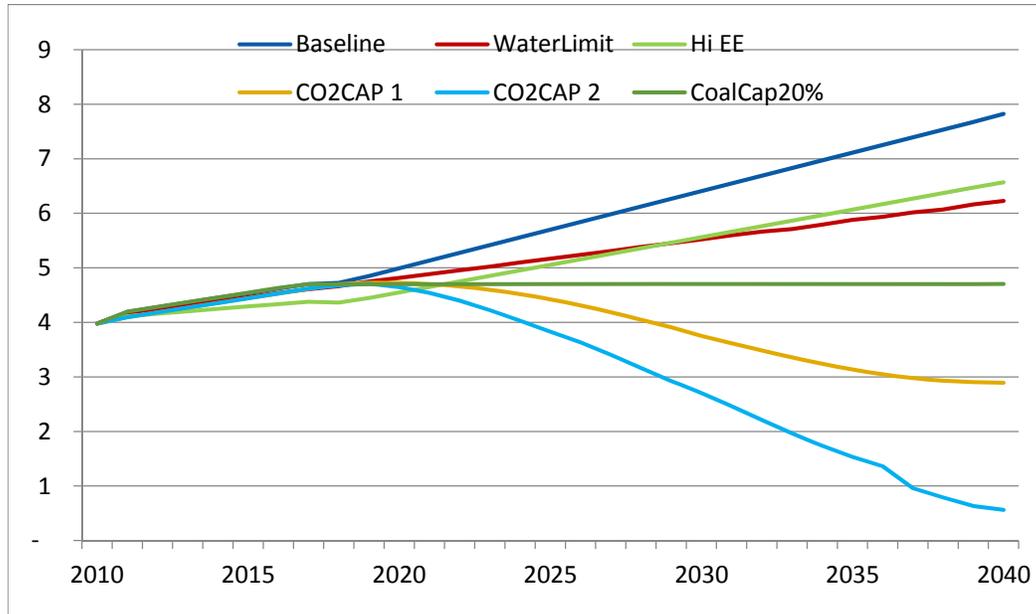
Figure 11. CO<sub>2</sub> emissions by scenario



Units = million tons/year

SO<sub>2</sub> emissions are almost directly proportional to the quantity of coal generation in the fuel mix, unsurprisingly bringing the Baseline, High-EE, and WaterLimit to the top of figure 12 as a result of their inability to offset a growing coal portfolio. High EE merely slows the growth of the coal portfolio, and thus SO<sub>2</sub> emissions. The WaterLimit scenario utilizes significant amounts of dry cooling, which reduces water consumption but ultimately has a negative effect on air emissions. The one exception to this relationship is CO<sub>2</sub>CAP 1, which sees SO<sub>2</sub> emissions fall despite a substantial coal portfolio. This is because CCS technology is able to remove significant amounts of SO<sub>2</sub> as a technical requirement of the technology. CCS is expected to increase NOx and particulate matter (PM) emissions in quantities relative only to the parasitic load required for capture and sequestration. Of course, SO<sub>2</sub> reductions can also be achieved by employing scrubbers and other control options.

Figure 12. SO<sub>2</sub> emissions by scenario



Units = million tons/year

### Cost

Because demand grows significantly in the China North Grid regions, the fixed and variable costs inevitably rise as well. The results for total system costs—which include amortized capital costs, fixed and variable O&M, and fuel costs,—fall into three groupings, as is seen in figure 13. The Baseline, WaterLimit, and CO<sub>2</sub>CAP 2 scenarios are quite similar—a surprising outcome, considering that the scenarios themselves are so varied. Total costs rise over the 30-year simulation period in the same pattern as the increase in demand, growing by 160 percent.

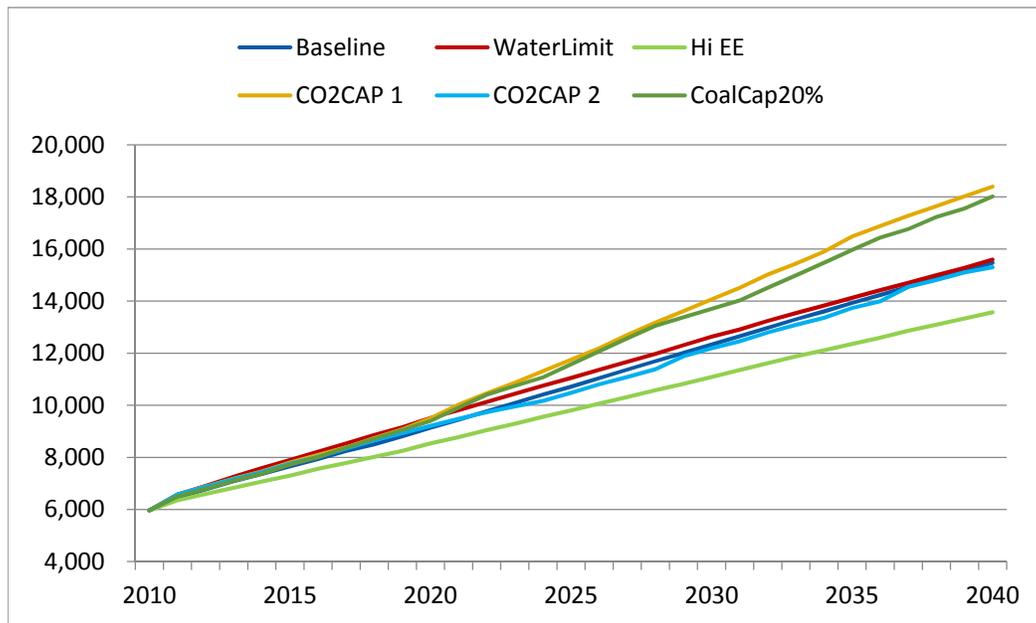
The lowest increase in total system costs occurs with the High-EE scenario, because demand reduction results in significantly lower capital, fixed and variable O&M, and fuel costs. We assume a cost for each MWh of generation avoided, but it is about half the cost of a unit of coal generation.<sup>39</sup> In each of the indicators we considered, greater end-use EE provides a positive result relative to the Baseline.

<sup>39</sup>. Tim Woolf, William Steinhurst, Erin Malone, and Kenji Takahashi, *Energy Efficiency Screening: How to Properly Account for “Other Program Impacts” and Environmental Compliance Costs* (Montpelier, VT: RAP, 2012), p. 9, [www.raponline.org/document/download/id/6149](http://www.raponline.org/document/download/id/6149).

The CO<sub>2</sub>CAP 1 and CoalCap 20% scenarios are the most costly of the group, but for different reasons. The big hit for the CO<sub>2</sub>CAP 1 scenario comes from fixed costs. The scenario posits a heavy reliance on coal with CCS to achieve the cap. Capital costs for coal with CCS are two-thirds higher, and fixed costs per MWh of generation are 40 percent higher than coal without CCS.

In contrast, the Coal Cap 20% scenario relies on wind and gas to make up the difference in generation that cannot be met by coal because of the assumed regulatory limit. As noted, we have assumed in this scenario that there is no decline in gas prices due to unconventional gas resources, leaving variable costs (not shown) 60 percent higher than the Baseline by 2040.

Figure 13. Total system costs by scenario



Units = billion Yuan/year

## China North Grid modeling summary and conclusions

Given that parts of China are already experiencing rolling blackouts due to insufficient water availability for power plant cooling, it is clear that China already faces serious water challenges in the power sector. The policy and technology choices made to meet demand will have immense implications for water withdrawals and

consumption, and may also have significant economic, human health, and development consequences.<sup>40</sup>

Among the primary challenges in meeting growing electric demand while utilizing water resources sustainably are the many conflicts evident in serving multiple important goals, and the numerous contexts and regulatory frameworks in which these decisions are made and conflicts resolved. This challenge is especially evident in the China North Grid region as a result of its dominant coal portfolio, limited existing renewable generation, and underdeveloped framework for utilizing unconventional gas. Meeting emissions reductions with the predominant energy technology—coal—seem nearly impossible in this region, as demonstrated in our primary CCS scenario, CO<sub>2</sub>CAP 1. While this technology could significantly reduce CO<sub>2</sub> and SO<sub>2</sub> emissions, CCS will dramatically increase water withdrawal, consumption, and capital costs, indicating it is highly unlikely this technology is tenable in the water-stressed and fast growing North Grid. Similar findings were evident in the WaterLimit scenario; heavily utilizing dry cooling for coal didn't substantially increase relative costs and did reduce water use in this scenario, but these efforts had much less of an effect on reducing CO<sub>2</sub> emissions that are driving climate change and exacerbating future EWN liability as precipitation anomalies become increasingly commonplace.

Unlike recent developments in the U.S., unconventional gas resources have been slow to develop in China, and estimates of existing reserves are wide ranging though expected to be significant and perhaps the largest in the world.<sup>41</sup> Coal-bed methane (CBM) resources have been a focal point for China, and the country has more than doubled its production target for 2015 as compared to 2010, but it is having trouble meeting that target.<sup>42</sup> China still has large strides to make before developing the necessary physical and regulatory infrastructure required to take advantage of these

<sup>40</sup> Human health impacts relating to the extraordinary use of coal in China has become an increasing point of concern for the government and Chinese people. Despite the significance of these impacts this topic is not explored in this report.

<sup>41</sup> The U.S. Energy Information Administration estimates these reserves at 1,274.85 tcf, while Chinese estimates range between 886 tcf (China Ministry of Land and Resources) and 1,084 tcf (China National Petroleum Corporation). See Jane Nakano, David Pumphrey, Robert Price Jr., and Molly A. Walton, *Prospects for Shale Gas Development in Asia: Examining Potentials and Challenges in China and India* (Washington, DC: Center for Strategic and International Studies, August 2013), p. 3.

<sup>42</sup> From 9.1 bcm in 2010 (actual production) to 21.5 bcm in 2015 (target), per the 12th Guideline. See, for example, Z. Yan, "Rules to Govern Foreign Participation in cbm," *China Daily*, November 4, 2011, [http://www.chinadaily.com.cn/business/2011-11/04/content\\_14035589.htm](http://www.chinadaily.com.cn/business/2011-11/04/content_14035589.htm); Herman K. Trabish, "China Backs Off Shale Gas Targets," *Greentech Media*, June 28, 2013, <http://www.greentechmedia.com/articles/read/china-backs-off-shale-gas-targets>.

resources in larger quantities.<sup>43</sup> Strong growth is predicted in light of China’s recent and increasing investment and demonstrated concern for severe air pollution issues. Nevertheless, even some of the most optimistic sources don’t find gas resources surpassing 10 percent of total energy consumption by 2030.<sup>44</sup> Despite the fact that hydraulic fracturing does itself consume water, it consumes a very small fraction per MWH<sup>45</sup> of produced fuel; and while this figure will vary by region and practices used, it is not expected to change the consumption figures for combined cycle gas turbine (CCGT) plants in a meaningful way, thus ensuring this resource will have significant net water benefits as compared to coal if capitalized. If China is able to secure affordable imports of gas resources and/or continues to aggressively develop them domestically in the future, it is likely that gas generation will be an important supply-side resource in addition to wind and other RE technologies for meeting demand, with water withdrawal and consumption needs far below those for an expanding coal portfolio.

Due to the particularly high sensitivity of the North Grid to water resource constraints, policy and technology choices that reduce water use while meeting demand will be of greatest importance to the North Grid over the long term. As demonstrated by the High-EE case, demand side EE investment will be critical to reducing the need for new thermal generation, total system costs, and impacts across all categories. Though we do not present an estimate for the North Grid, China overall has significant remaining potential for demand-side reduction.<sup>46</sup> Echoing

<sup>43</sup> See, for example, Simon Montlake, “Shale Gas Revolution Not Coming to China Anytime Soon,” *Forbes*, October 30, 2013, <http://www.forbes.com/sites/simonmontlake/2013/10/30/shale-gas-revolution-not-coming-to-china-anytime-soon/>.

<sup>44</sup> Demand estimates vary widely—BP: 9 percent of total demand at 15.6tcf in 2030; Exxon: 281tcf in 2030, U.S. Energy Information Administration: 6 percent by 2035; and China National Petroleum Corporation (via Jiping Zhou, VP): 17.66tcf by 2030. See Nakano et al., *Prospects for Shale Gas Development in Asia*, p. 2.

<sup>45</sup> Water consumption for hydraulic fracturing is ultimately a different type of consumption than we discuss for traditional thermal sources. In this case, water is injected into a well and either remains within a formation or returns as produced water that is typically filtered and reused or disposed in salt wells. Figures offered on a series of gas-only wells operated in the United States by Chesapeake Energy revealed that hydraulic fracturing consumes an extremely minimal amount of water per produced unit of fuel. For Chesapeake Energy, their highest-consuming shale play, the Barnett Shale in the ERCOT region of Texas, consumption figures were a mere 0.0037 m<sup>3</sup>/MMBtu, which translates to just 0.0012 m<sup>3</sup>/MWH of produced fuel. It is however important to note that this figure—while it will vary between wells, regions, and company—is quite minimal as compared to the consumption of a thermal generator and will not significantly add to the per MWH consumption of a thermal plant fired by natural gas.

<sup>46</sup> B. Finamore, D. Moskovitz, J. Plunkett, P. Mosenthal, S. Slote, and F. Wyatt, “Demand-Side Management Strategic Plan for Jiangsu Province, China: Economic, Electric, and Environmental Returns from an End-Use Efficiency Investment Portfolio in the Jiangsu

earlier recommendations, a supply-side path focused heavily on promoting renewable energy, particularly wind in the North Grid regions, will reduce water resource use and also reduce the need for new thermal generation while decreasing the risk associated with the tight coupling of service reliability and water availability in this region. In all the cases that we looked at, limiting the growth of coal generation over the long-term proved to be essential to limiting growth in water demand for energy production. It also seems evident that renewable energy in tandem with a heavy demand-side focus will be increasingly necessary.

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Power Sector,” *Proceedings of the 2006 ACEEE Summer Study on Energy Efficiency in Buildings*, vol. 5, *Utility Regulation and Competition: Incentives, Strategies, and Policies* (Washington, DC: American Council for an Energy-Efficient Economy, 2006). For example, 3.5 GW of EE measures exist for industrial motor/drive systems alone that could be obtained at a cost on the order of \$250/kW, or less than about \$0.03 per kWh.

# India

## Introduction

India's water situation may be even more serious than China's. Currently around 52 percent of India's population lives in water-scarce regions, and 73 percent of the electricity capacity owned by the country's three large utilities—NTPC, Tata Power, and Reliance Power—is located in water-scarce or stressed regions.<sup>47</sup> While this is problematic for any region, it is especially bad for India, given its long-standing electric supply woes; demand has steadily outstripped supply in India for years, with a deficit of 10.2 percent in 2012 after an 11 percent gap in 2009.<sup>48</sup>

Power supply challenges achieved further notoriety in 2012 when India experienced the largest power blackout in world history, affecting around 600 million people with a two-day disruption in several northern states.<sup>49</sup> This event brought both significant short-term economic losses and some damage to the nation's standing as a robust emerging economy.<sup>50</sup> Currently, there are large gaps to fill: an estimated 289 million people in India (about 25 percent of the population) live without access to electricity, and 914 million (about 80 percent of the population) are dependent on solid fuels for cooking and household energy needs.

<sup>47</sup> FICCI-HSBC Knowledge Initiative, *Water Use and Efficiency in Thermal Power Plants* (New Delhi: Federation of Indian Chambers of Commerce and Industry, 2011). Water stress occurs when the demand for water exceeds the available amount during a certain period or when poor quality restricts its use. Water scarcity is defined as the point at which the aggregate impact of all uses impinges on the supply or quality of water to the extent that the demand by all sectors cannot be satisfied fully.

<sup>48</sup> For the figures on the deficit trend, see J. Yardley, "2nd Day of Power Failures Cripples Wide Swath of India," *The New York Times* (July 31, 2012), <http://www.nytimes.com/2012/08/01/world/asia/power-outages-hit-600-million-in-india.html?pagewanted=1&r=1>; Gevorg Sargsyan, Mikul Bhatia, Sudeshna Ghosh Banerjee, Krishnan Raghunathan, and Ruchi Soni *Unleashing the Potential of Renewable Energy in India* (Washington, DC: The World Bank, 2010), p. 7.

<sup>49</sup> For example, "Hundreds of Millions Without Power In India," BBC News, July 31, 2012, <http://www.bbc.co.uk/news/world-asia-india-19060279>.

<sup>50</sup> "Blackout Nation: Power Cuts in India Show That a Lack of Reform Is Beginning to Hurt Ordinary People," *The Economist* (August 4, 2012), <http://www.economist.com/node/21559941>.

## Case study selection

We selected India as a case study for three main reasons:

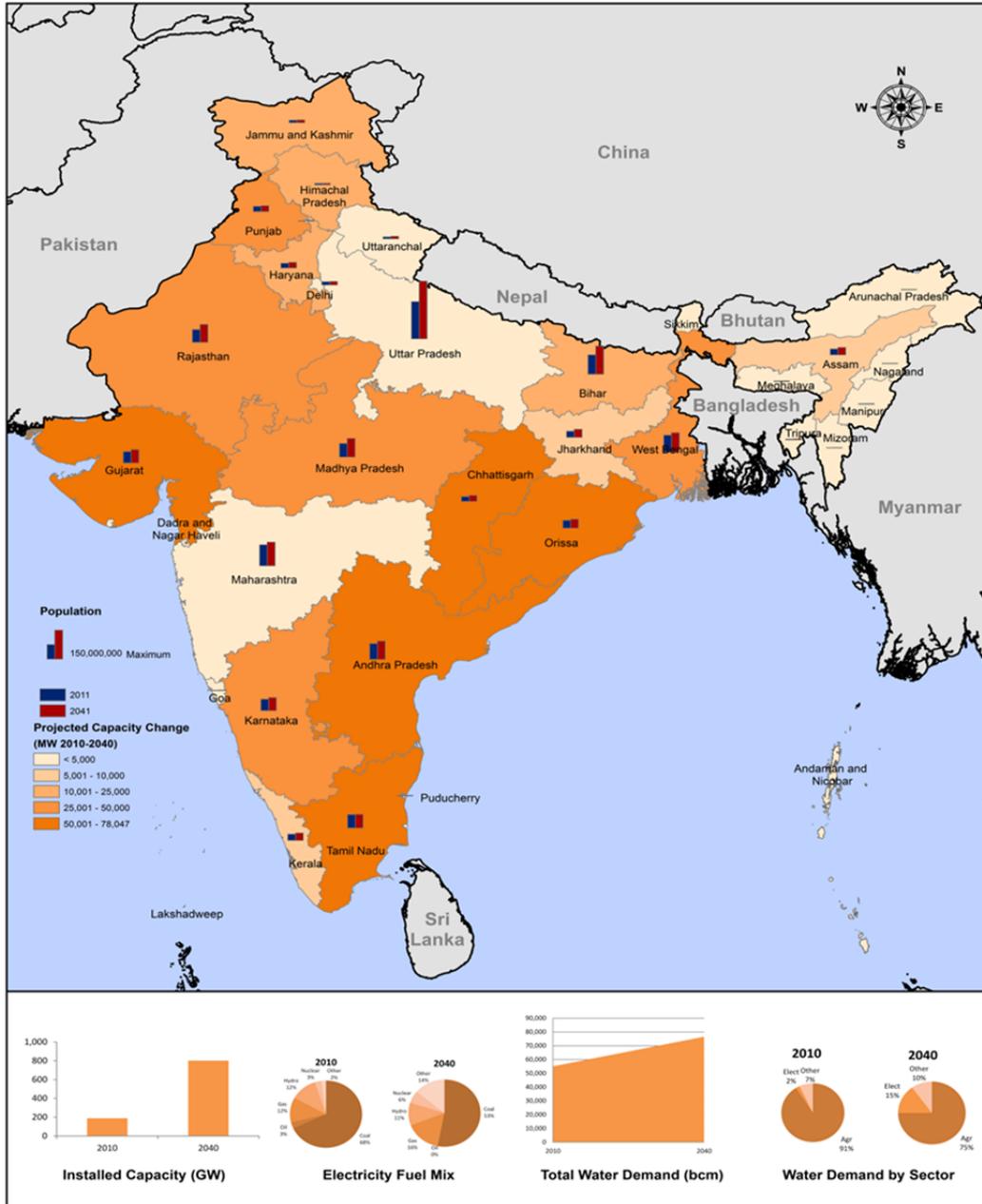
1. Large portions of the country are already water scarce and water stressed.<sup>51</sup>
2. It has a large capacity supply gap it wants to close.
3. India is experiencing strong economic growth and has a very large population.

Figure 15 offers an overview of these three trends.

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<sup>51</sup> Sauer, Klop, and Agrawal, Over Heating.

Figure 14. India projected population growth and capacity change by state, 2010–2040



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Note: These maps can be found on CNA's website: [www.cna.org](http://www.cna.org) <sup>b</sup>. Another footnote.

First, the high water intensity of electricity generation forces it to compete with other water-intensive sectors. India's primary water sources include snowmelt and rainfall during the monsoon season, and are naturally not distributed evenly, spatially or temporally.<sup>52</sup> Eighty percent of India's river flows are accounted for during the summer monsoon season from June to September, and weak or delayed monsoons habitually cause water shortages and droughts, particularly severe in 2009 and 2012.<sup>53</sup> The northwest and southern regions are highly vulnerable to water shortages, making power plants vulnerable as well.<sup>54</sup> Many plants have been forced to shut down repeatedly during the driest months of the year.<sup>55</sup> Shortages of water have also forced Indian state planners to make hard decisions about whether to divert freshwater for irrigation or to meet the cooling needs of thermoelectric power plants.

Second, India has maintained a serious capacity deficit for over a decade—now estimated at 10.2 percent in 2012—with nearly 400 million people lacking access to electricity.<sup>56</sup> Under the Electricity Act of 2003, the government must close this substantial access gap.<sup>57</sup> Total installed capacity in 2013 was estimated at about 230GW in 2013 by official Indian sources, the vast majority of which is produced by thermal generators that account for 66 percent of this capacity.<sup>58</sup> State government-sponsored companies own more than half of the nation's power plants, and central government corporations own a third. Conventional thermal power plants produced about 80 percent of the country's electricity, with nuclear, hydro, and other renewable sources making up the remainder. Coal generates the majority of power, at about 70 percent in 2009, fueled by low-quality domestic grades of coal and substantial imports.<sup>59</sup>

Third, India has the world's second largest population, estimated at 1.26 billion in 2012, which places high demands on comparatively undersized natural water

<sup>52</sup> "Water Profile of India," Encyclopedia of Earth, March 19, 2012, <http://www.eoearth.org/view/article/156948/>; see also Central Water Commission, *Annual Report 2010-11* (New Delhi: Government of India/Ministry of Water Resources, 2011).

<sup>53</sup> *Ibid.*

<sup>54</sup> International Energy Agency, *World Energy Outlook 2012*.

<sup>55</sup> Vladimir Smakhtin, Carmen Revenga, and Petra Döll, *Taking into Account Environmental Water Requirements in Global-Scale Water Resources Assessments* (Washington, DC: World Resources Institute, 2004).

<sup>56</sup> Yardley, "2nd Day of Power Failures Cripples Wide Swath of India."

<sup>57</sup> India Electricity Act of 2003, Part IV, Section 43(1).

<sup>58</sup> Central Statistics Office/National Statistical Organization, *Energy Statistics 2013* (New Delhi: Government of India/Ministry of Statistics and Program Implementation, 2013).

<sup>59</sup> Sun-Joo Ahn and Dagmar Graczyk, *Understanding Energy Challenges in India: Policies, Players, and Issues* (Paris: International Energy Agency, 2012).

resources.<sup>60</sup> The World Resources Institute estimates that water demand will outstrip supply by as much as 50 percent by 2030, a situation worsened further by the country's likely decline of available freshwater due to climate change.<sup>61</sup> Because of competition, agriculture's share of water withdrawals is expected to drop from 90 percent now, to 70 percent by 2025.<sup>62</sup> India's ambition to provide power for all may prove a major challenge, as 79 percent of new capacity is expected to be built in water-scarce or water-stressed areas.<sup>63</sup>

## Modeling analysis of power generation scenarios for India: 2010–2040

For this case, we draw from a study done for the Planning Commission of India by Lawrence Berkeley National Laboratory (LBNL) and others (including RAP) entitled *Modeling Clean and Secure Energy Scenarios for the Indian Power Sector in 2030*.<sup>64</sup> The authors looked at the application of renewables and efficiency to help reduce continuing power shortages and potentially large coal imports that will be necessary if India remains dependent on coal for a large share of its power generation. The study highlights the growing global demand for coal and increasing volatility in coal prices. In contrast, estimates of India's renewable resources are growing, and their costs are coming down.

The LBNL study considered three scenarios looking out to 2030. We extended these to 2040 using a straight-line trend.

### Indian Scenarios

1. **Baseline**, which uses the Indian government's 12<sup>th</sup> Plan projection up to 2022 and extends it up to 2030, and which we extended to 2040. The demand projection is taken from the Power and Energy Working Group report for the 12<sup>th</sup> Plan. Demand grows to almost 4.5 GWh per year; almost six times greater than in 2010. The shares

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<sup>60</sup> United Nations Development Programme, Human Development Report 2013—The Rise of the South: Human Progress in a Diverse World (New York: UNDP, 2013), p. 196.

<sup>61</sup> Sauer, Klop, and Agrawal, *Over Heating*, p. 19.

<sup>62</sup> Encyclopedia of Earth, "Water Profile of India."

<sup>63</sup> See, for example, the India Electricity Act of 2006, Part VI ("Duty to Supply"), Section 43; *ibid.*

<sup>64</sup> Nikit Abhyankar, Amol Phadke, Jayant Sathaye, Ranjit Bharvirkar, Alissa Johnson, Ranjit Deshmukh, Cathie Murray, Bob Lieberman, and Ajith Rao, *Modeling Clean and Secure Energy Scenarios for the Indian Power Sector in 2030*. LBNL Report (Berkeley, CA: Lawrence Berkeley National Laboratory, May 2013), <http://eetd.lbl.gov/sites/all/files/lbnl-6296e.pdf>.

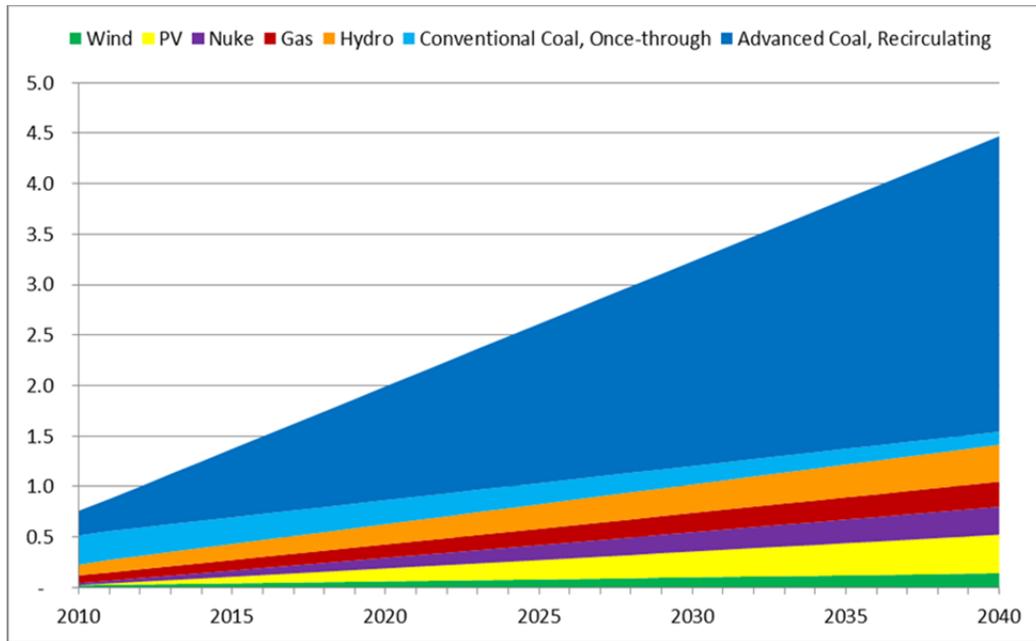
of hydro and nuclear power are constant across the scenarios, while the share of gas is the same for the first two, and halved in the last.

2. **A Modestly Secure and Clean Scenario (Modest)**, which assumes that wind, PV, and energy efficiency make up 40 percent of the mix by 2030.
3. **An Aggressively Secure and Clean Scenario (Aggressive)** that has wind, PV, and energy efficiency making up 60 percent of the total by 2030. The LBNL report concludes that wind and solar resources will not be a constraining factor to renewable power generation, as these are as much as six times the power demand expected in 2030.

### *Baseline scenario*

Figure 15 shows the fuel mix for the Baseline scenario. We have broken out two options for production of power from coal, the first using conventional technology and once-through cooling, and the second utilizing advanced coal technology with recirculating cooling. For the purposes of this simulation we've modeled conventional coal at a subcritical heat rate and modeled advanced coal as supercritical. We assumed that in 2010 coal capacity is split 50/50 between these two and that only advanced coal can be used in the future as a result of new policies. Thus the graphic shows a declining amount of conventional coal as it gradually retires, while advanced coal grows quite dramatically. The total share of coal generation starts and ends at about 70 percent. Nuclear power's share starts at about 3 percent and doubles over the course of the run, while hydro starts at 13 percent and ends up at 8 percent, even though generation from hydropower grows by about 250 percent over this same period. Gas drops from 9 percent to 6 percent, and PV and wind increase from 3 percent to 12 percent, while growing dramatically by a factor of 23; yet these increases are dwarfed by the growth in coal generation.

Figure 15. Baseline power generation fuel mix for India

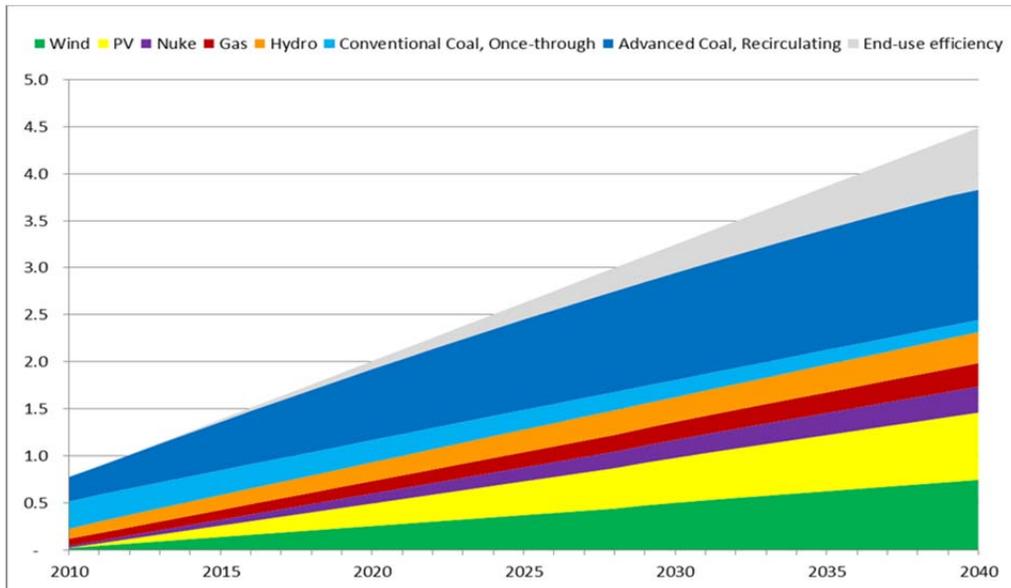


Units = million GWh/year

### *Modest and Aggressive scenarios*

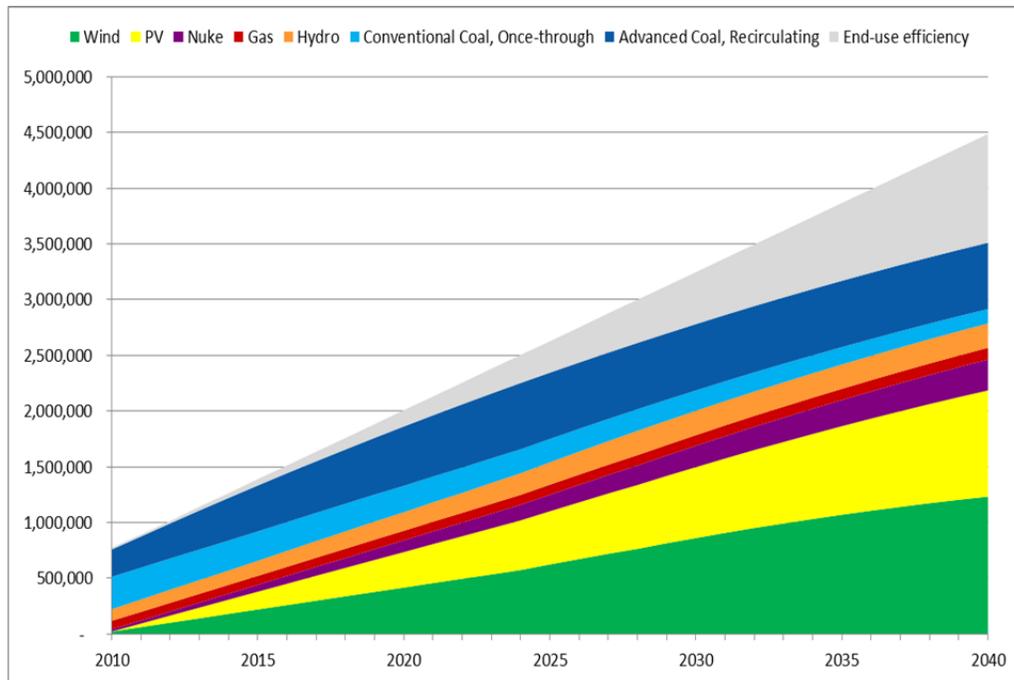
The Modest and Aggressive scenarios are presented in figures 16 and 17. In both cases, as solar PV and wind increase, the use of coal for power generation drops dramatically—from about 70 percent, to 34 percent and 17 percent, respectively. Shifts of these magnitudes away from coal would have major benefits for India by reducing water withdrawals and consumption from the power sector, and improving service reliability by limiting exposure to water resource constraints.

Figure 16. Power generation fuel mix for Modest scenario



Units = million GWh/year

Figure 17. Power generation fuel mix for Aggressive scenario



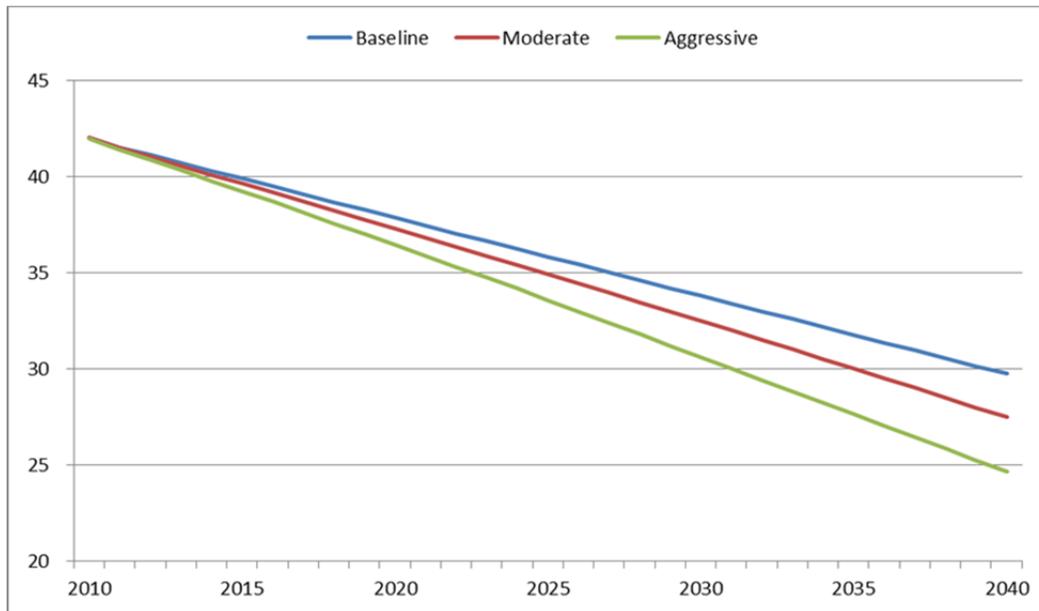
Units = million GWh/year

## Cross-scenario comparisons

### Water withdrawal

We calculate water withdrawals in 2010 for cooling water to be a bit above 40 billion cubic meters (bcm)/year. By 2040 these withdrawals would decline between 30 percent and 40 percent, primarily because conventional coal using once-through technology, which accounts for the majority of withdrawals, is retiring from the fleet or undergoing retrofit to utilize a recirculating system. Withdrawals from advanced coal using recirculating cooling are much smaller, so withdrawals go down in all three scenarios (see figure 18).

Figure 18. Water withdrawal by scenario



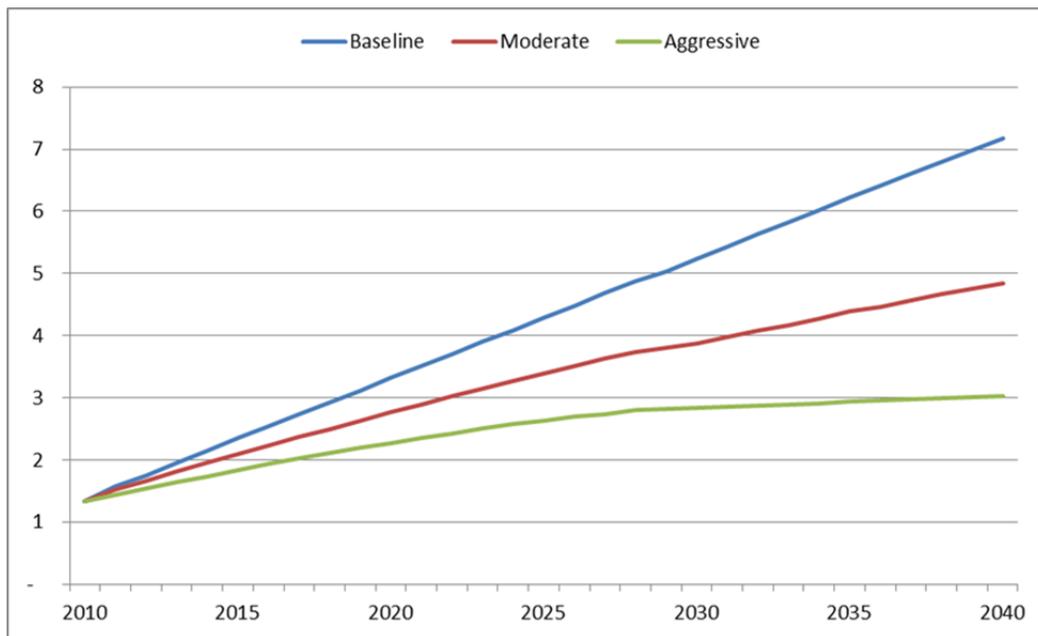
Units = bcm/year

### Water consumption

In contrast to water withdrawals, water consumption goes up markedly. Figure 20 provides our estimates of water consumption for the power sector, including thermal cooling and evaporative losses from hydro. The difference between the scenarios is

substantial: Water consumption in the Baseline starts at about 1.4 bcm per year and increases by about 500 percent, while the Moderate scenario sees increases of almost 350 percent, and the Aggressive scenario by about 215 percent. Though water consumption in the Aggressive scenario goes up the least, it still represents more than a doubling of water consumption for power generation by 2040 as driven by a coal portfolio that is expanding in capacity though being reduced in its overall share. Given the status of India’s already stressed water resources, these large consumption increases—even under the aggressive scenario—indicate available water will be drawn from other sectors of the economy, most likely agriculture. Ultimately, growth in water consumption appears to be unavoidable considering the enormous scale of expected future demand growth. Given the rising value of water to the economy into the future, the benefits of the Aggressive scenario are likely to be enormous.

Figure 19. Water consumption by scenario



Units = bcm/year

## Water-use efficiency

In the Moderate and Aggressive scenarios, the productivity of water use in the power sector (liters consumed/MWh) improves substantially as shown in table 3. Where the water productivity for the Baseline increases by just 7 percent, it improves by 37 percent and 61 percent, respectively, for the Modest and Aggressive scenarios, in line with the share of renewables and efficiency. These are substantial gains in the use of an increasingly scarce and valuable resource.

Table 4. Water productivity in the power sector for India (liters/MWh)

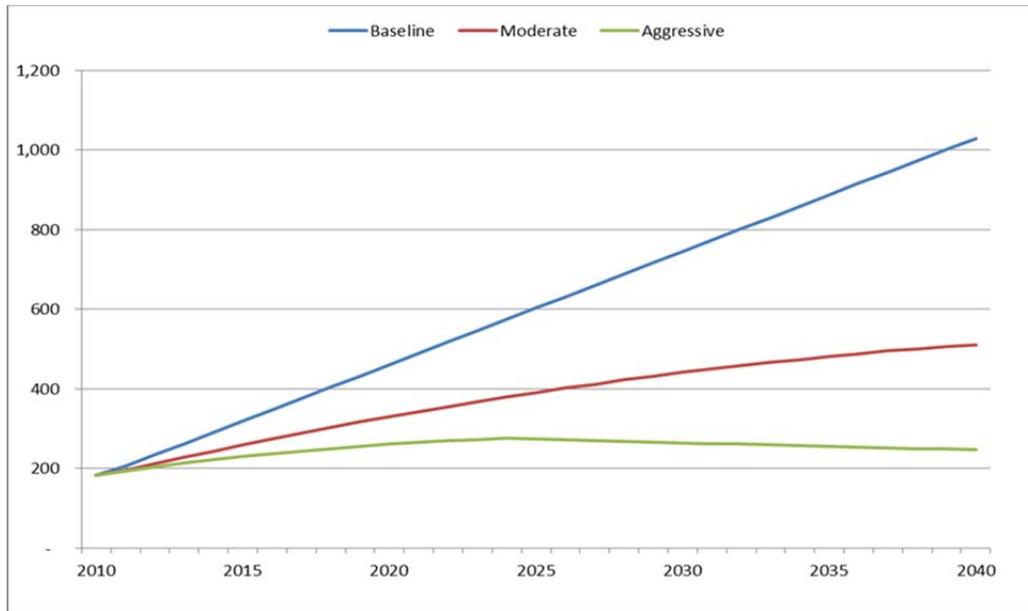
	Baseline	Modest	Aggressive
2010	1,717	1,717	1,717
2040	1,600	1,079	675
Improvement in Water Productivity	7%	37%	61%

### *Emissions*

The second major benefit of a shift away from coal and toward efficiency and renewables would be in the form of better air quality relative to the Baseline. Coal is the only source of conventional air pollutants such as SO<sub>2</sub>, mercury, and PM in the power sector, and is also the largest source of NO<sub>x</sub> emissions, with natural gas being the next most significant in this regard.

In figure 20, we look at SO<sub>2</sub> emissions as an example. In the Baseline, SO<sub>2</sub> emissions grow by approximately 530 percent; a similar growth rate to that seen for water consumption in the same scenario. The increases in SO<sub>2</sub> emissions seen in the Moderate and Aggressive scenarios are much lower, at about 265 percent for the Moderate scenario and only about one-third for the Aggressive scenario by the end of the simulations. Smaller increases are seen for mercury, PM, and NO<sub>x</sub> for all the scenarios because advanced supercritical coal technology has fewer of these emissions than conventional subcritical coal, though the trends are similar. For the Aggressive scenario, all of these indicators show a small increase and then a return to about one-third above the starting point by 2040.

Figure 20. SO<sub>2</sub> emissions by scenario

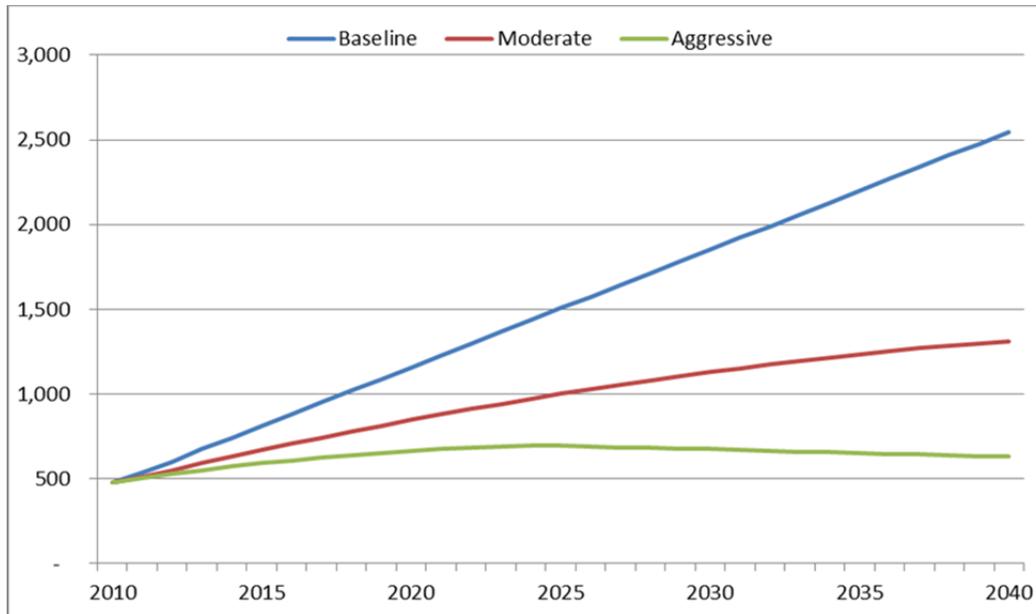


Units = thousand tons/year

The results for CO<sub>2</sub> emissions presented in figure 21 look nearly identical to the figure for SO<sub>2</sub>, the principal difference being scale. We calculate CO<sub>2</sub> emissions in 2010 to be 480 million metric tons year. In the Baseline, CO<sub>2</sub> emissions go up by about 500 percent, while the increase is about 260 percent for the Moderate scenario, and just under one-third for the Aggressive scenario by the end of the simulation.

What's notable about this graph is that it shows a pathway to meet power demand in India in a way that only marginally increases greenhouse gas emissions. And it does this without the use of CCS technology, which nearly doubles water withdrawals and consumption for coal-fired generation, an option that does not appear tenable in India.

Figure 21. CO<sub>2</sub> emissions by scenario



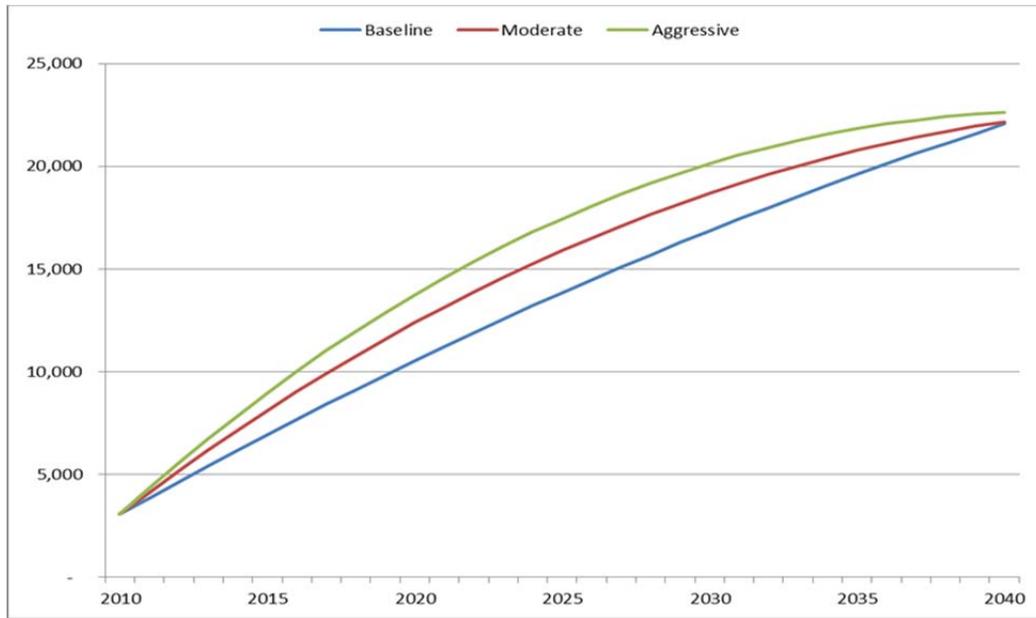
Units = million tons/year

### Costs

Large power sector benefits can be delivered for a fairly small incremental cost, shown in figure 22 as annual total system costs for each scenario in billions of rupees. For the Moderate case, the additional costs over the 30-year period are 10 percent more than the Baseline. For the Aggressive case, they are 18 percent greater. The graph shows the lines converging at the end of the simulation period as costs decline and capacity factors go up for wind and PV. Based on analysis of wind capacity factors in India and trends in the industry, we expect capacity factors to rise above their current levels as experience develops and this technology is more efficiently utilized.<sup>65</sup> The effect of improving capacity factors for wind and PV is to reduce their costs over time. This results in the convergence of the Aggressive scenario with the other two. We assume constant generating capacity factors for coal, nuclear, hydro, and gas power.

<sup>65</sup> Abhyankar et al., Modeling Clean and Secure Energy Scenarios for the Indian Power Sector in 2030.

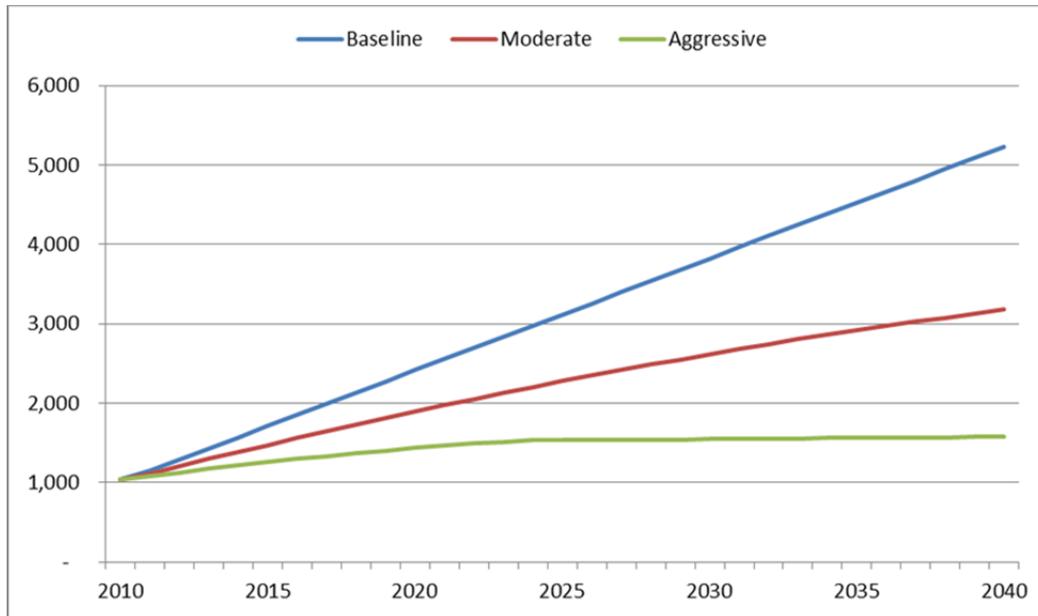
Figure 22. Total system costs by scenario



Units = billion Rs./year

Figure 23 shows that variable costs, including fuel costs, go up linearly in the Baseline by about 500 percent over the simulation period. In contrast, these costs go up by almost half as much in the Moderate scenario, at around 300 percent. The smallest increase is seen for the Aggressive scenario—at just over 50 percent by 2040—due to the dominance of efficiency, wind, and PV, which have no associated fuel costs. Reduced exposure to the uncertainty and expense of fuel price variability offers the Indian economy significantly greater energy security and a minimized dependence on coal imports.

Figure 23. Variable costs



Units = billion Rs./year

## India modeling summary and conclusions

With very rapid growth expected over the next several decades, India represents the extreme of the case studies we examined. Ultimately, India is facing two highly challenging circumstances: a very significant existing electricity demand gap, and considerably stressed water resources under mounting pressures from a growing economy and population. Meeting high electricity demand in India with thermal generation would be a challenge even with unlimited water resources, but the nation is in a position in which it somehow must supply this growth without them.

Analysis of India's water resource constraints, existing thermal generation, and growth expectations raises questions about the possibility of a long-term energy path that relies heavily on thermal generation, and almost certainly eliminates the possibility of using CCS for CO<sub>2</sub> mitigation due to its negative effect on water use. Solving this challenge in such a way that allows India to continue high growth while avoiding water scarcity risks, reducing per unit power sector emissions, and meeting demand at least cost will ultimately require significant renewable energy investments on the supply side, coupled with strong demand-side energy efficiency efforts, which even at the high end, are still cheaper than new coal capacity. Fortunately, the incremental costs to achieve these gains are modest due to declining wind and PV

costs, and diminish by the end of the scenarios. This trend, however, may still likely be insufficient to offset the need for new thermal generation unless deployed quickly, particularly as India takes important steps toward providing electricity to a broader base of its growing population. Thus it is also strongly recommended here that India use care to place a moratorium on new thermal generation not using dry cooling or seawater in the most water scarce regions in order to avoid increasingly frequent service disruptions as a result of water scarcity, and to preserve these resources for other segments of the economy.

A path defined largely by EE and RE is increasingly competitive with a Baseline scenario over the simulation period, and recognizes the strong EE and RE path (here modeled as the Aggressive scenario) to bear considerably lower exposure to the variable fuel costs that may increase the risk of increasing commitments to coal generation.

In addition to numerous benefits including reduced water consumption, withdrawal, emissions, and improved reliability, the Modest and Aggressive scenarios also offer energy security and energy independence benefits for India, a consideration that was paramount in the LBNL analysis done for the Planning Commission of India.

# France

## Introduction

With a population of about 63 million, France was both the ninth largest producer and consumer of electricity in the world in 2012.<sup>66</sup> Roughly 75 percent of France's electricity production came from its large nuclear fleet in 2012—the highest share in the world by a wide margin—and the nation was the second largest net exporter of electricity in the world, behind Paraguay at 31 terawatt-hours (TWh) in 2010.<sup>67</sup>

The French nuclear sector is unique because reactor designs have been standardized by design and capacity, typically sized at 900MW, 1300MW, or 1450MW. The electric grid's high dependency on nuclear power means that some reactors serve peak instead of base load power, sometimes ramping down during the weekends to follow load and often exporting power during times of surplus capacity. While the industry has high plant availability figures, load following produces an overall average capacity factor in the 70 percent range, which is low by world standards; the global average in 2010 was 85 percent<sup>68</sup>

Resources to fuel other traditional thermal generation sources in France are quite limited. There are currently no operating coal mines in France, and it has very little natural gas production—though France is thought to have considerable shale gas resources.<sup>69</sup> As coal and gas resources diminished, France embarked on a centralized energy policy oriented toward investment in nuclear infrastructure and technology.

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<sup>66</sup> For an overview of France's demographic and energy consumption data, see U.S. Central Intelligence Agency, "France," *The World Factbook*, Jan. 14, 2013, available at <https://www.cia.gov/library/publications/the-world-factbook/geos/fr.html>; *BP Statistical Review of World Energy 2013*; and World Nuclear Association. Data available at: <http://www.world-nuclear.org/info/Facts-and-Figures/Nuclear-generation-by-country/#.UkrawYakrOM>.

<sup>67</sup> See International Energy Agency, *Key World Energy Statistics* (2012 edition; data, 2010 edition) (Paris: IEA).

<sup>68</sup> *Ibid.*

<sup>69</sup> U.S. Energy Information Administration, *Technically Recoverable Shale Oil and Shale Gas Resources: An Assessment of 137 Shale Formations in 41 Countries Outside the United States* (Washington, DC: EIA, 2013), <http://www.eia.gov/analysis/studies/worldsharegas/pdf/overview.pdf>.

The Commissariat à l'Énergie Atomique was charged with developing a French gas-graphite reactor. A growing French population, an expanding economy, an increase in the number of dwellings, and more industrial output led to increased nuclear power usage and a proliferation of nuclear power plants built between the late 1970s and early 1990s.<sup>70</sup>

Four nuclear power plants along the coast use seawater for cooling, while inland power plants require freshwater for cooling. Eleven of the fifteen inland plants use recirculating cooling systems, and the remaining four use an open-loop regime and emit thermal discharge directly to rivers or lakes.<sup>71</sup>

## Case study selection

We selected France as a case study for this report primarily for

1. the large water footprint of its electricity sector and the resulting vulnerabilities to water shortages and heat;
2. its unusually high dependence on nuclear generation, a highly water-intensive resource; and
3. France's role as a major exporter of electricity.

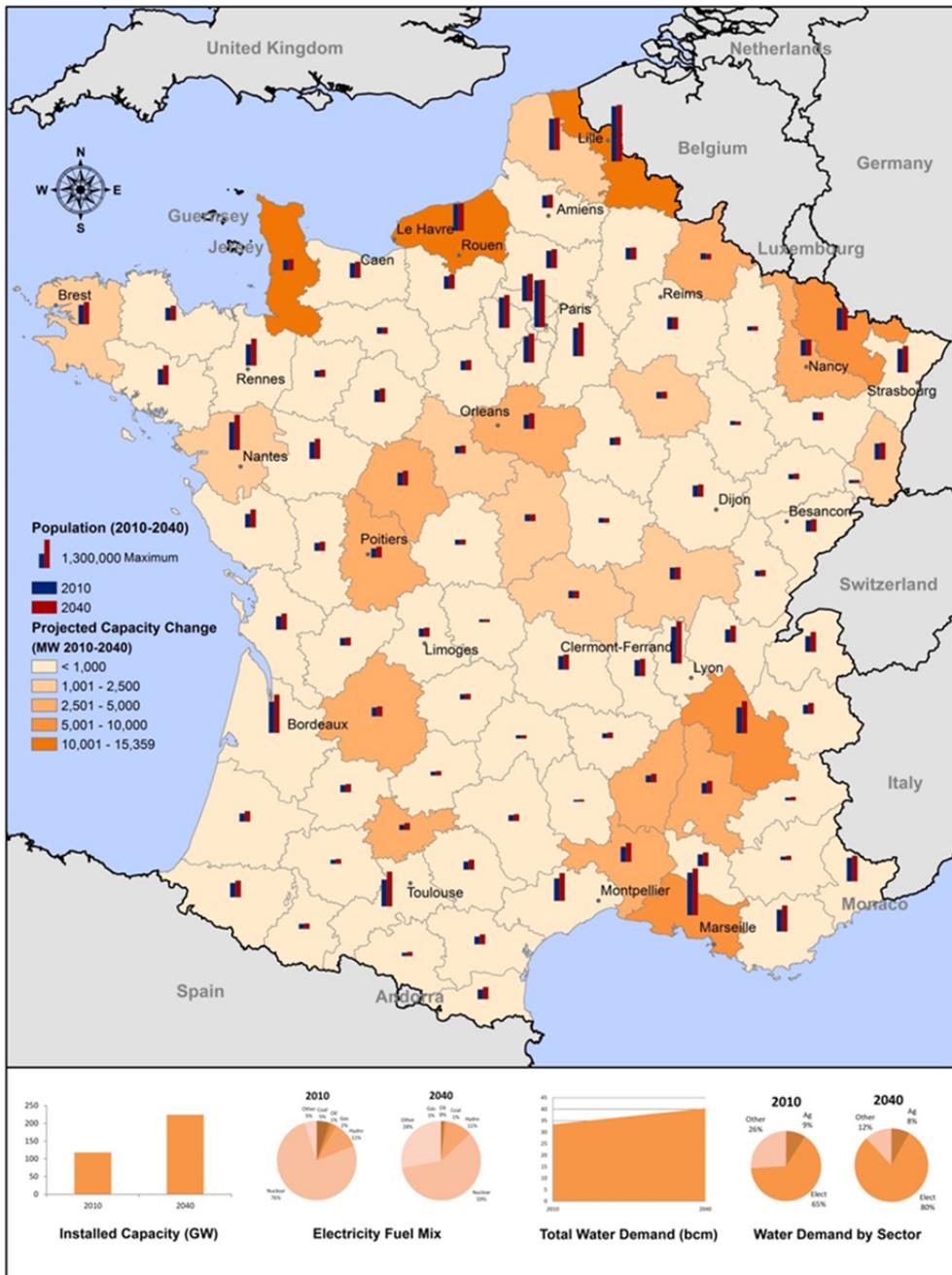
As Figure 24 indicates, the regions that used the most water closely reflect the nuclear and thermal power footprint in France: (1) Rhône-Alpes, (2) Aquitaine, (3) Alsace, (4) Pays de la Loire, (5) Ile-de-France, (6) Provence-Alpes-Côte d'Azur, (7) Languedoc-Roussillon, (8) Lorraine, and (9) Centre. Regional population projections through 2040 show total water use is expected to remain highest in these nine regions, five of which also correspond with anticipated population growth of more than 500,000 by 2040. Importantly, the convergence of demand from a growing population and heavy nuclear generation will likely put additional stresses on existing freshwater resources and exacerbate the total water use dilemma in these heavily populated regions.

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<sup>70</sup> World Nuclear Association, *Optimized Capacity: Global Trends and Issues 2012*. A Report by the World Nuclear Association's Capacity Optimization Working Group (London: World Nuclear Association, 2012), p. 8.

<sup>71</sup> U.S. Energy Information Administration, "France: Country Analysis Note," March 2013, <http://www.eia.gov/countries/country-data.cfm?fips=FR>.

Figure 24. France projected population growth and capacity change by province, 2010–2040



Note: These maps can be found on CNA's website: [www.cna.org](http://www.cna.org)

First, the French energy sector is vulnerable because it uses a majority of the country's water. More precisely, 64 percent of water withdrawn in France in 2009 was dedicated to cooling nuclear power plants, though the government estimates only 10 percent of withdrawn water was consumed.<sup>72</sup> Unusual heat and drought presents major challenges for nuclear generation for two reasons: river levels must be high enough to support cooling cycles (i.e., there must be enough water by quantity), and, particularly for once-through cooling plants, the body of water receiving thermal discharge must not be warmer than a regulated range to meet environmental compliance and protect surrounding ecosystems; this second factor is not particularly relevant for plants that utilize ocean water for cooling.

In the 2003 drought, the temperature of the discharge sources exceeded environmental safety levels on several counts.<sup>73</sup> In order to ensure adequate electricity supply, an exception was granted to allow six reactors to exceed water discharge temperature requirements, prompting criticism that thermal discharge threatened the environment during a state of already high water temperatures.<sup>74</sup>

Similar troubling situations have occurred in France more recently. In 2009, a power workers strike and a drought combined to take as much as 20 GW of France's nuclear generating capacity offline, leading France to become a net importer of electricity during the month of October for the first time in 27 years.<sup>75</sup> The heat wave also exposed an important reality in the EU as it simultaneously disrupted power generation in Germany, the Netherlands, and neighboring countries: during times of extreme weather and high demand, overdependence on thermal generation can threaten the reliability of electricity service across an entire region.

Second, nuclear power using recirculating (or closed-loop) cooling has the highest water consumption rates of any conventional power generation technology.<sup>76</sup>

<sup>72</sup> Commissariat Général au Développement Durable, *Les prélèvements d'eau en France en 2009 et leurs évolutions depuis dix ans*. Chiffres et Statistiques, No. 290 (Paris: CGDD, February 2012), <http://www.developpement-durable.gouv.fr/IMG/pdf/CS290.pdf>.

<sup>73</sup> United Nations Environmental Programme. "Impacts of Summer 2003 Heat Wave in Europe," Environmental Alert Bulletin 2, n.d., [http://www.grid.unep.ch/products/3\\_Reports/ew\\_heat\\_wave.en.pdf](http://www.grid.unep.ch/products/3_Reports/ew_heat_wave.en.pdf).

<sup>74</sup> Ibid.; Amelia Gentleman, "France Faces Nuclear Power Crisis," *The Guardian* (August 13, 2003), <http://www.guardian.co.uk/news/2003/aug/13/france.internationalnews>.

<sup>75</sup> Robin Pagnamenta, "France Imports UK Electricity as Plants Shut," *The Times of London*, July 3, 2009, <http://www.thetimes.co.uk/tto/business/industries/utilities/article2198065.ece>; Réseau de Transport d'Électricité, *The French Electricity Report 2009* (Paris: RTE, 2010), [http://www.rte-france.com/uploads/media/pdf\\_zip/publications-annuelles/rte-be09-en-02.pdf](http://www.rte-france.com/uploads/media/pdf_zip/publications-annuelles/rte-be09-en-02.pdf).

<sup>76</sup> Mielke, Anandon, and Narayanamurti, *Water Consumption of Energy Resource Extraction, Processing, and Conversion*. p. 32.

Considerable reliance on nuclear generation makes France particularly sensitive to water shortages and heat waves, and this has proven dangerous for France in recent times. For five weeks during the record-breaking summer heat wave in 2003, France lost 7 percent to 15 percent of its nuclear electricity supply in addition to 20 percent of its hydroelectric capacity. Lasting from June through mid-August, the heat wave had curtailed about 4 GW of capacity by late summer, and while France's power sector was able to keep pace with domestic demand, it significantly curtailed exports to neighboring countries.<sup>77</sup>

Third, as France is a significant exporter of electricity to Italy, Belgium, Switzerland, Great Britain, and, to a lesser degree, Spain, reliability concerns also pose risk exposure to many of its European neighbors, though this factor is not specifically considered in this report.<sup>78</sup> Germany is the only neighboring country with which France is a net importer of electricity; in 2012 imports outpaced exports by a factor of over 2:1, largely due to the growth of renewable energy and cheap domestic and imported coal from Germany, among other factors.<sup>79</sup>

## Modeling analysis of power generation scenarios for France: 2010–2040

The predicted Baseline growth in demand for power in France—28 percent over 30 years—is very modest relative to the other case studies we examine in this report. Accompanying this growth is an increase in generating capacity and demand for cooling water, though these are expected to grow at a much more measured pace than for China and India. Nevertheless, because the power sector is already such a dominant user of water in the country due to its heavy dependence on nuclear generation, even modest increases are of concern for the rest of France's economy due to water use and the vulnerability of the power sector. Policies currently under consideration, such as limiting nuclear power's share of generation and increasing renewable energy, could reverse this trend.

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<sup>77</sup> See, for example, "Heatwave Hits French Power Production," *The Guardian* (August 12, 2003), [www.theguardian.com/world/2003/aug/12/france.nuclear](http://www.theguardian.com/world/2003/aug/12/france.nuclear).

<sup>78</sup> See "France Net Power Exporter Except to Germany," Renewables International, January 23, 2013, <http://www.renewablesinternational.net/france-net-power-exporter-except-to-germany/150/537/59937/>.

<sup>79</sup> Ibid.

**French Scenarios** utilized the report of the European Commission's Directorate-General for Energy (DG ENER), *EU Energy Trends to 2030: Update 2009*,<sup>80</sup> as a basis for developing our French model scenarios:

1. **The Baseline** taken from the DG ENER's report uses estimates for electricity generation and generating capacity by fuel to 2030. We have extended this scenario through 2040 using a straight-line projection.
2. **A limit of 50 percent for nuclear power generation by 2035 (Nuclear 50%)**. This scenario was prompted by political discussion in France aimed at curtailing nuclear power and substituting for it with renewables. This has been the position of President François Hollande, but is appearing less likely on the basis of the cost advantage of existing nuclear generation. Nonetheless, this scenario still offers a valuable perspective on what this policy choice could mean for France.
3. **Fixed water availability (WaterLimit)** limits water consumption to the amount calculated by the model for the Baseline in 2010.
4. **High end-use efficiency (High-EE)**, assumes a decline of two-thirds of a percent in demand from the Baseline.

### *Baseline*

Our reproduction of the baseline from the DG ENER's report is presented in figure 25. Total generation grows from 567 thousand GWh in 2010, as given by the DG ENER, to 678 thousand GWh in 2030. Our ten-year extension brings the 2040 total to about 730 thousand GWh, an increase of 28 percent over 2010.

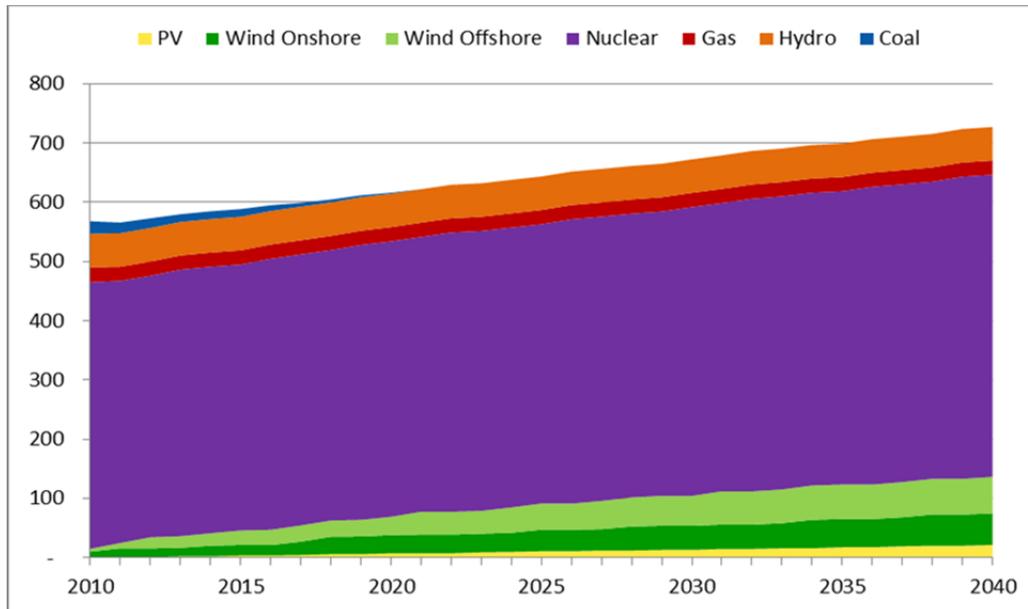
The model shows that nuclear power grows by about 13 percent through 2040, though its share of total generation drops from 79 percent to 71 percent over the same period. Hydro and gas are mostly unchanged, and their shares slowly decline as generation increases. Coal starts from a small base and disappears before the end of the simulation. By contrast, wind and PV grow from a small fraction to 19 percent of generation. We constrained the model to reproduce the DG ENER's baseline, but when the model is allowed to choose based on least cost, wind and PV increase to 24 percent by 2040.

The slight lumpiness observed in these results is due to the large impact that a single nuclear power plant has on total capacity when it comes online or is retired.

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<sup>80</sup> European Commission, Directorate-General for Energy, *EU Energy Trends to 2030 (Update 2009)* (Luxembourg: Publications Office of the European Union, 2010), [http://ec.europa.eu/energy/observatory/trends\\_2030/doc/trends\\_to\\_2030\\_update\\_2009.pdf](http://ec.europa.eu/energy/observatory/trends_2030/doc/trends_to_2030_update_2009.pdf).

Figure 25. Baseline power generation fuel mix for France



Units = thousand GWh/year

### *Nuclear 50%*

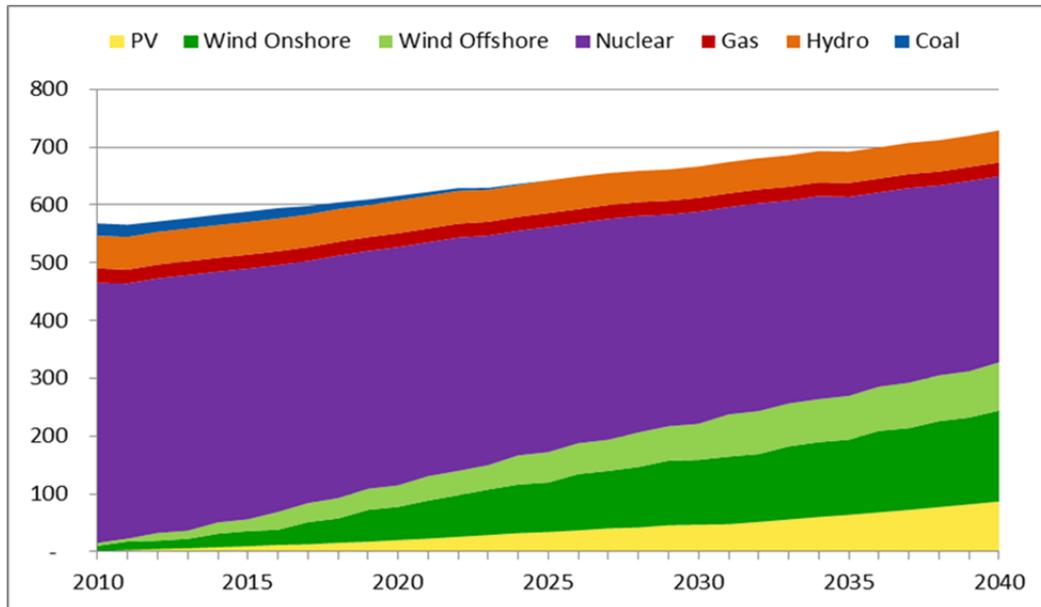
The fuel mix for the Nuclear 50% scenario is presented in figure 26. Of particular note is that any additional costs associated with the accelerated decommissioning of existing nuclear facilities have not been included. Assuming a reduction can be made in nuclear capacity without incurring additional costs, renewables play a strong role in this model and provide 45 percent of total generation by 2040, with wind accounting for one-third of total generation and PV making up the difference. After the United Kingdom, France has the second highest on- and offshore wind potential in Europe, and it could meet 25 percent of its 2030 power demand on about 15 percent of its agricultural land.<sup>81</sup>

For this case study we broke out the wind resources into onshore and offshore, as there are considerable offshore development opportunities in France with quite different costs and capacity factors. Though the amortized capital costs for offshore wind are more than double those for onshore, the higher relative capacity factors make offshore wind competitive in France. We utilized capacity factors for each of

<sup>81</sup>. European Environment Agency, *Europe's Onshore and Offshore Wind Energy Potential: An Assessment of Environmental and Economic Constraints*. EEA Technical Report No. 6/2009 (Luxembourg: Office for Official Publications of the European Communities, 2009).

the generation options from the generation and capacity values given by the DG ENER’s 2030 report: The capacity factor for onshore wind was about 20 percent, offshore wind was assumed at 40 percent, 12 percent for PV, and 72 percent for nuclear. Onshore wind and PV capacity factors were adjusted up over the course of the simulation to 35 percent and 20 percent, respectively.

Figure 26. Nuclear 50% power generation fuel mix

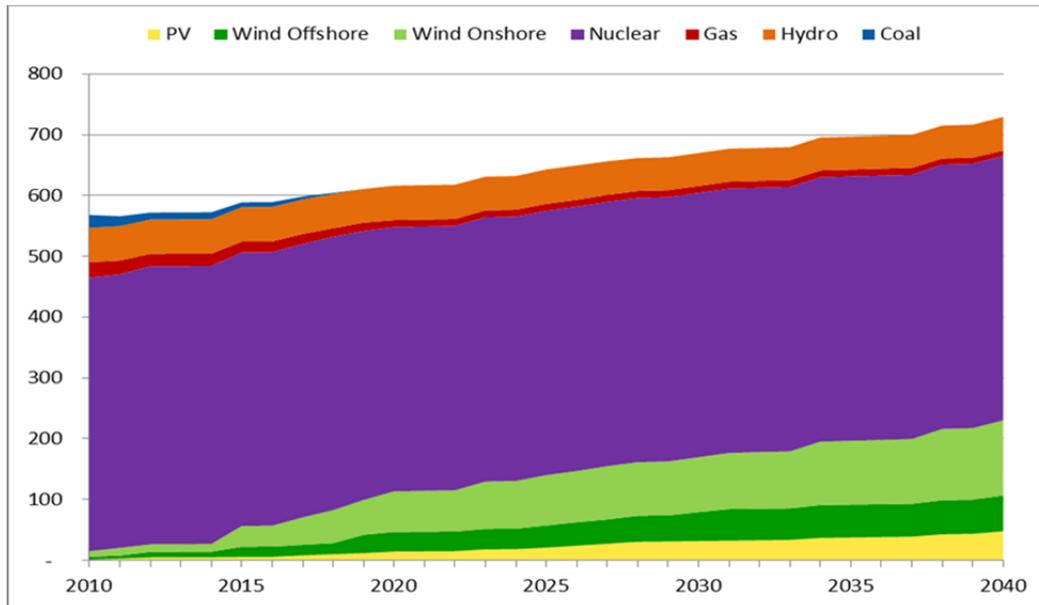


Units = thousand GWh/year

### *WaterLimit scenario*

In the WaterLimit scenario, water consumption is limited to that calculated in the 2010 Baseline. This enables existing nuclear capacity to remain in use, but constrains this capacity from expanding in any meaningful way as a result of its high water-intensity. As demand grows through 2040, this gap from existing nuclear capacity is filled by renewables (see figure 28). The scenario shows that the development of nuclear power would be constrained if no more water was available to the sector, though not as much as under the Nuclear 50% scenario.

Figure 27. WaterLimit power generation fuel mix



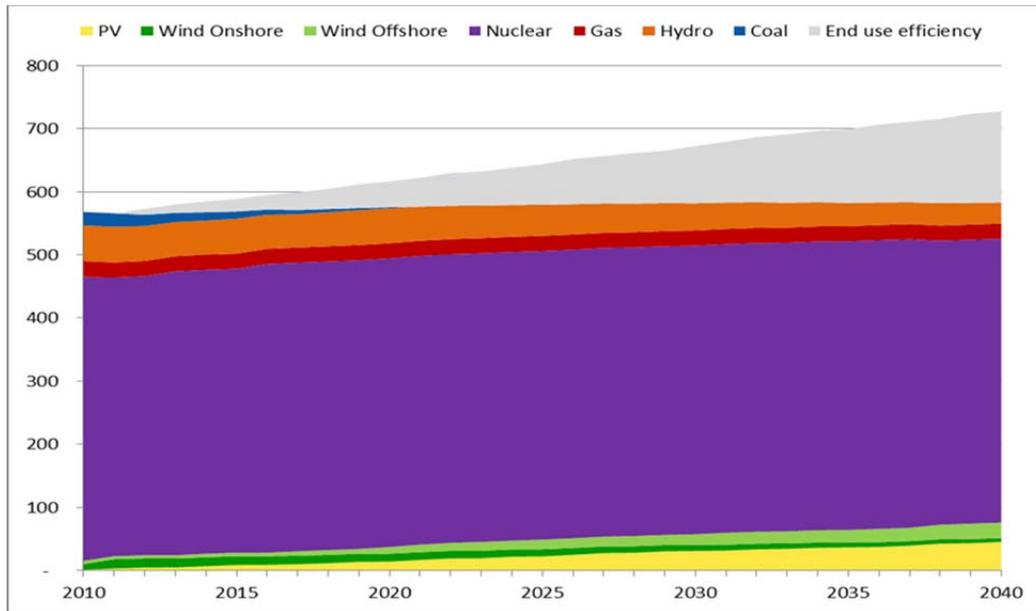
Units = thousand GWh/year

### *High-EE scenario*

In the High-EE scenario shown in Figure 28 demand is reduced by two-thirds of a percentage point per year, which is roughly equal to total expected demand growth.<sup>81</sup> In this scenario, high demand-side energy efficiency investment reduces new capacity needs over the simulation period. Replacement capacity comes largely from wind and PV as old nuclear plants are retired.

<sup>81</sup> European Commission, Directorate-General for Energy, *EU Energy Trends to 2030 (Update 2009)*, p. 85.

Figure 28. High-EE power generation fuel mix



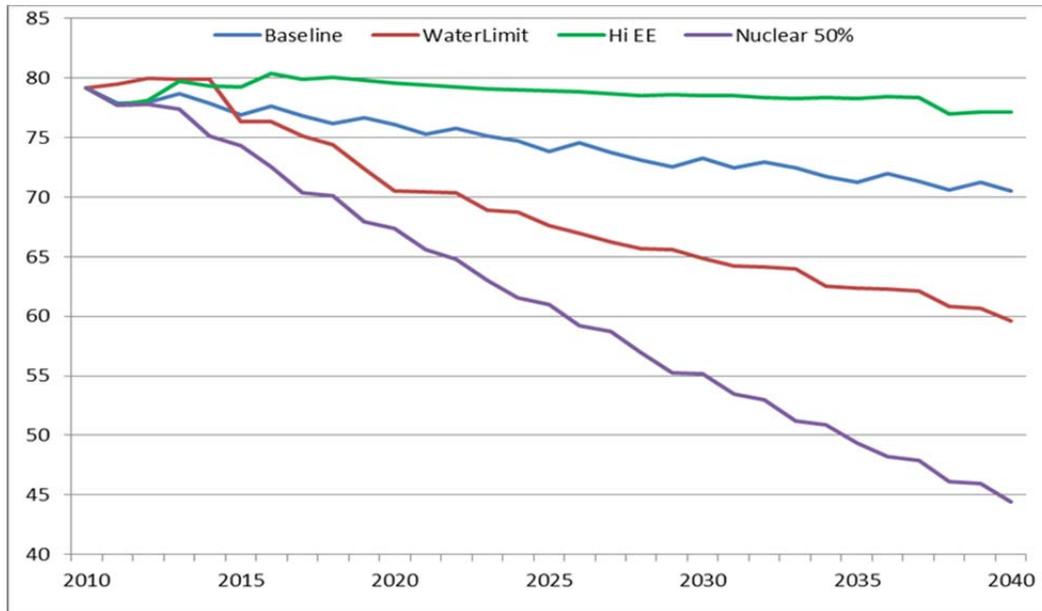
Units = thousand GWh/year

## Cross-scenario comparisons

### Nuclear power

Modeling results for the share of nuclear power in the generation mix are shown in figure 30. As previously noted, the Baseline share falls from 79 percent to 71 percent due to retirements being replaced by wind and PV. This decline occurs more slowly with the High-EE scenarios and quite a bit faster under WaterLimit. The Nuclear 50% scenario drops dramatically, as expected, hitting 50 percent at 2035 and 44 percent by the end of the run. Nuclear generating capacity drops in real terms under this policy scenario, from about 70 GW to just under 50 GW, while wind and PV take up the slack and all of the growth.

Figure 29. Share of nuclear power in total generation by scenario

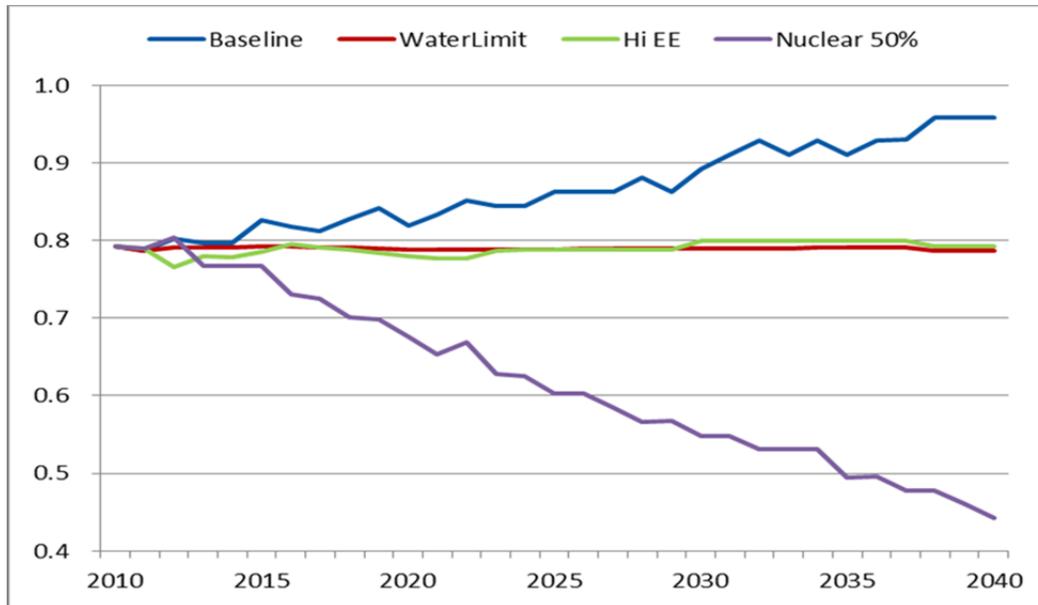


Units = %

## Water consumption

Water consumption varies quite dramatically across the scenarios we tested, from an increase of about 21 percent, to a decline of about 44 percent (as shown in figure 31). The WaterLimit scenario keeps water consumption flat, as intended, and the High-EE scenario does so as well by eliminating generation growth. Even though generation grows by 28 percent in the Baseline, the demand for cooling water goes up only by about 21 percent, due to the growing share of wind and PV and the elimination of the small amount of coal. The most dramatic change is produced by the Nuclear 50% scenario, which would yield a substantial decrease in water consumption of nearly 50 percent.

Figure 30. Water consumption by scenario



Units = bcm/year

In table 4, we show water use productivity stated as liters of water consumed per MWh for 2010 and 2040. We used a value of 2,246 liters/MWh for nuclear power with recirculating tower cooling, and 1,018 for plants with once-through, open-loop cooling (based on Macknick et al.). The numbers in this table are lower than the other case studies, because ocean cooling accounts for 30 percent of cooling water in France (utilizing virtually no freshwater/MWh); the use of some once-through cooling in France (which withdraws more but consumes less); and the growing amounts of wind and PV that require no water, practically speaking, and require no cooling.

Table 5. Freshwater productivity by scenario for France (liters/MWh)

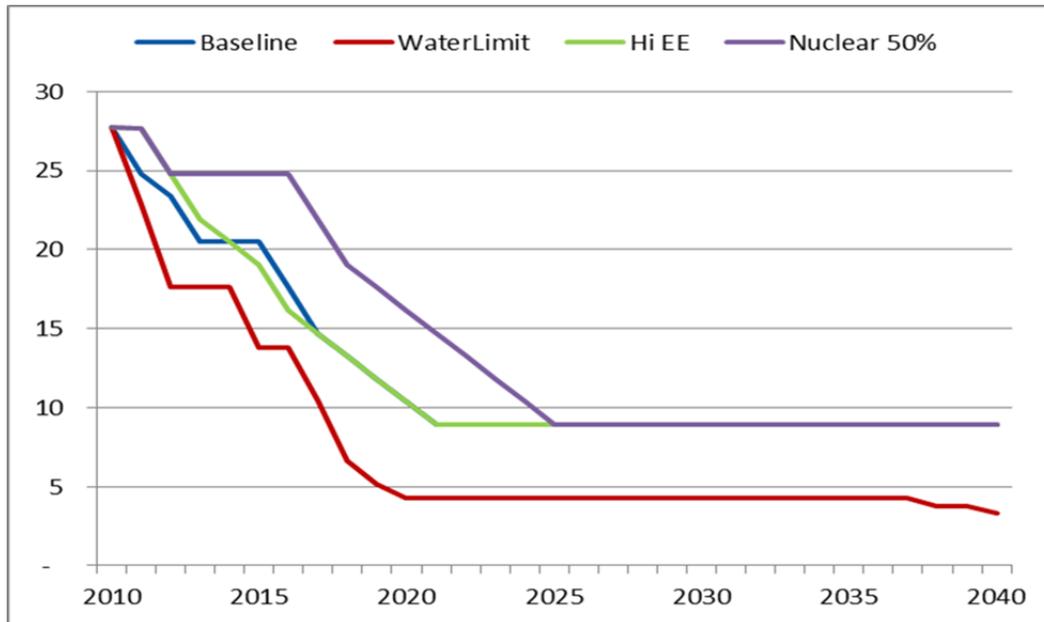
	Baseline	WaterLimit	High Efficiency	Nuclear 50%
2010	1,396	1,396	1,396	1,396
2040	1,319	1,078	1,080	689
Increase in water productivity	6%	23%	23%	51%

### Emissions

Nuclear power is essentially free of carbon dioxide emissions in power generation. As a result of France's high dependence on nuclear power and renewable energy in all our scenarios, CO<sub>2</sub> emissions start small and decline with the phase-out of the small

quantity of existing coal generation. SO<sub>2</sub> emissions (not shown) under all scenarios are small and expected to be negligible after 2025, with all but Nuclear 50% reaching a negligible level as soon as 2020 after coal generation is phased out. The WaterLimit scenario shows a greater drop than the other scenarios because it pushes coal out faster.

Figure 31. CO<sub>2</sub> emissions by scenario



Units = million tons/year

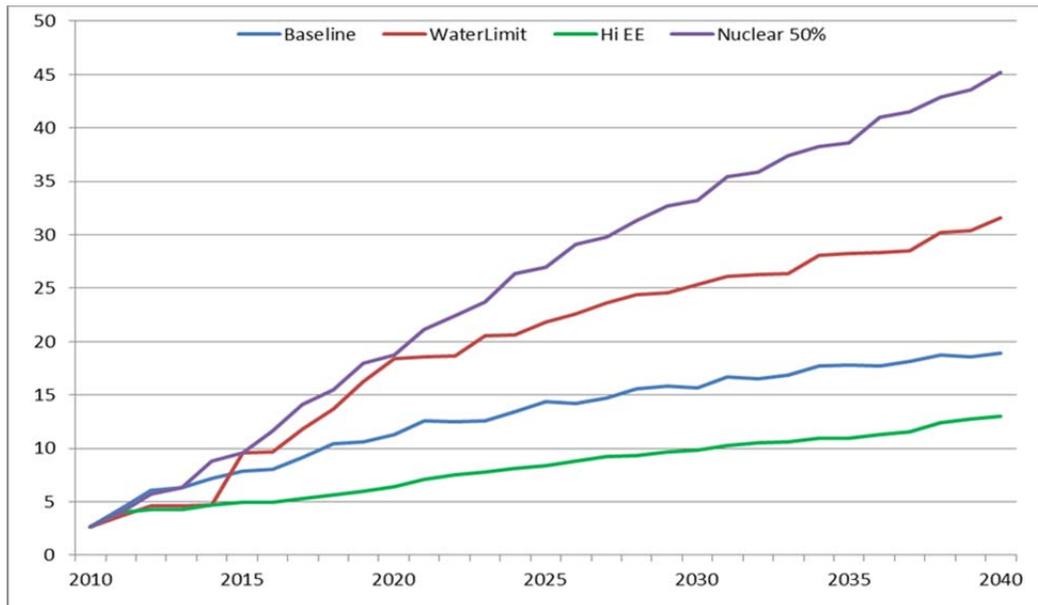
### *Wind and solar PV*

There are large differences between the scenarios for the share of wind and PV in the fuel mix, and they are virtually the mirror image of the nuclear shares for each scenario by trend (figure 33). The Nuclear 50% scenario results in the largest share of wind and PV due to the simulated limit on nuclear power, and the WaterLimit scenario also shows a large share of wind and PV because they consume little or no water. The High-EE scenario shows the least change over time because the net increase in demand from 2010 is only a few percent, so capacity additions are limited to turnover in the fleet.

Ultimately, even more wind and PV would be needed if there were a significant shift in balance between freshwater and seawater cooling. As discussed further in Section 4.4 increasing the use of unconventional gas in France seems to be a very unlikely source of future capacity; meeting increased demand above what is estimated in these scenarios without running high exposure to water scarcity risk would require

greater demand-side efforts, even more RE, seawater-cooled nuclear power, or a combination of all.

Figure 32. Share of wind and PV in total power generation



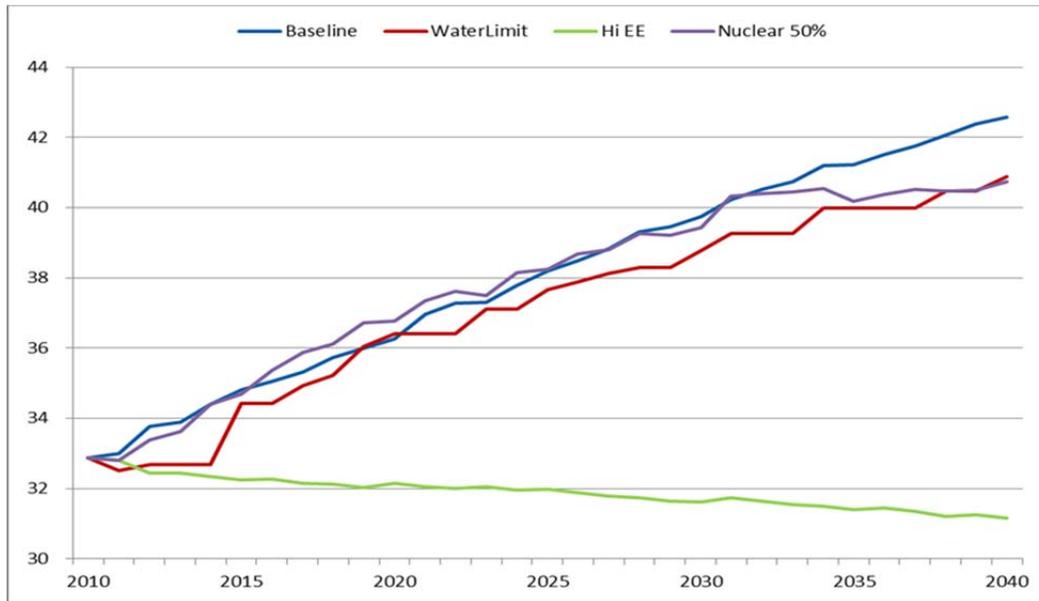
Units = %

### Costs

Total system costs (figure 34) shows a high degree of similarity between the results for three of the four scenarios. System costs are approximately the same for the Baseline, WaterLimit, and Nuclear 50%. The High-EE scenario stands out because its costs decline over time, as the costs of additional generating capacity are avoided and replaced with the lower cost of end-use efficiency.

Total fixed costs (not shown) look the same as total system costs, because fixed costs make up about 90 percent of the total system costs. This is because nuclear, hydro, wind, and PV all have high capital and fixed O&M costs and low or no fuel or variable O&M costs. For this reason, variable costs are a relatively small share of total cost for all the scenarios

Figure 33. Total system costs



Units = billion euros/year

## France modeling summary and conclusions

Though the political conversation surrounding the early retirement of a portion of France’s nuclear capacity hasn’t formally ended, it appears unlikely. Although President Hollande has publically championed reducing the share of nuclear generation, statements made by France’s Industry Minister Arnaud Montebourg held a hard line on the basis of comparatively low electricity prices.<sup>83</sup> Though this situation is still evolving, the prospect of France’s seeing a large reduction in nuclear capacity appears less likely; thus it will be increasingly important for France to utilize demand-side strategies to minimize future supply-side requirements and limit exposure to even larger economic losses and other risks when faced with water shortages and high heat, a condition familiar to France after its experience during a significant drought and heat wave in 2003.

As demand grows, however, our modeling suggests that the current nuclear-dominated energy path—when supported by demand-side investment (High-EE

<sup>83</sup>. T. Patel, “France Won’t Shut Any More Atomic Reactors, Minister Says,” Bloomberg News, November 12, 2013, [www.bloomberg.com/news/2013-11-12/france-won-t-shut-down-any-more-nuclear-reactors-minister-says.html](http://www.bloomberg.com/news/2013-11-12/france-won-t-shut-down-any-more-nuclear-reactors-minister-says.html).

case)—will reduce future water consumption increases, but will likely not be enough to reduce water consumption from current levels. As evidenced by the 2003 events, this means continued liability for France should it face similar events in the future; thus demand-side strategies likely will not be enough to avoid France’s current level of risk. Ultimately, supply-side resources will be required to reduce dependence on water-intensive nuclear generation. Such resources may come from among domestic RE, seawater-cooled nuclear, and/or further imports of cheap power from Germany, which is producing large shares of RE and, increasingly, coal power.<sup>84</sup>

Unlike all other case studies in this report, utilization of domestic shale gas resources appears mostly a non-option in France, particularly since a 2013 decision from its constitutional court upheld a 2011 law banning hydraulic fracturing.<sup>85</sup> Capacity growth from other traditional generation resources are also unlikely: domestic or imported coal would have a very difficult time as a result of its unfavorable impact on the country’s climate policies, and hydropower is relatively mature, with little room for significant future growth. With these traditional resources fairly constrained, it looks increasingly likely that France will be required to invest in its own RE infrastructure to hedge against its water-intensive nuclear supply, or else face complicated and costly logistical decisions as EWN exposure impacts grid reliability during future water shortages. Fortunately, France has significant on- and offshore wind resources, as well as good opportunities for PV, especially in the south.

Water constraints aside, new nuclear capacity is also extremely expensive to construct, even in a nation with considerable experience, standardized designs, and a centralized nuclear generation program. Based on all of these factors, RE is expected to be a competitive supply path for France, and will offer immeasurable benefits when water shortages endanger

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<sup>84</sup> See, for example, “France’s Power Net Exports Fall in 2012,” Reuters, January 22, 2013, <http://www.reuters.com/article/2013/01/22/france-power-grid-idUSL6N0AR6EN20130122>.

<sup>85</sup> Law No. 2011-835. See also “France Cements Fracking Ban,” *The Guardian* (October 11, 2013), <http://www.theguardian.com/environment/2013/oct/11/france-fracking-ban-shale-gas>.

# Texas

## Introduction

The state of Texas has a long history of producing fossil energy, including crude oil, natural gas, and coal.<sup>86</sup> It leads the U.S. in fossil fuel reserves, as well as non-hydroelectric renewable energy potential.<sup>87</sup> Texas leads the U.S. for planned electricity capacity additions, with plans to add more generation capacity than any other state through 2040.<sup>88</sup>

In the U.S., Texas has a unique electricity market. Unlike most states that share grid ties with other states and regions, the electric system in the Electric Reliability Council of Texas (ERCOT) region does not share synchronous connections with any other state; it is virtually an isolated system. The ERCOT Independent System Operator (ISO) serves about 22 million customers in Texas, manages the flow of electric power to 85 percent of the state's electric load, and schedules power on 405,000 miles of transmission lines from more than 550 generation units totaling about 62 GW of operational capacity—about 7 percent of the total installed capacity in the U.S.<sup>89</sup> Though the ERCOT region does not cover all of Texas, its role is substantial enough in the state that references to Texas and the ERCOT region are used somewhat interchangeably in this case study.<sup>90</sup>

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<sup>86</sup> Notably, Texas was the first state in the U.S. to reach 10GW of renewable energy capacity in 2010.

<sup>87</sup> U.S. Energy Information Administration, "Texas," State Profile and Energy Estimates, December 18, 2013, <http://www.eia.gov/state/analysis.cfm?sid=TX>.

<sup>88</sup> Binz et al., Practicing Risk-Aware Electricity Regulation.

<sup>89</sup> "About ERCOT," ERCOT, <http://www.ercot.com/about/>. See also ERCOT, "Report on the Capacity, Demand, and Reserves in the ERCOT Region," May 2012, <http://www.ercot.com/content/news/presentations/2012/CapacityDemandandReserveReport-2012.pdf>.

<sup>90</sup> For a good summary of EWN issues in Texas, see Ashlynn S. Stillwell, Carey W. King, Michael E. Webber, Ian J. Duncan, and Amy Hardberger, "The Energy-Water Nexus in Texas," *Ecology and Society* 16, no. 1 (2011): 2.

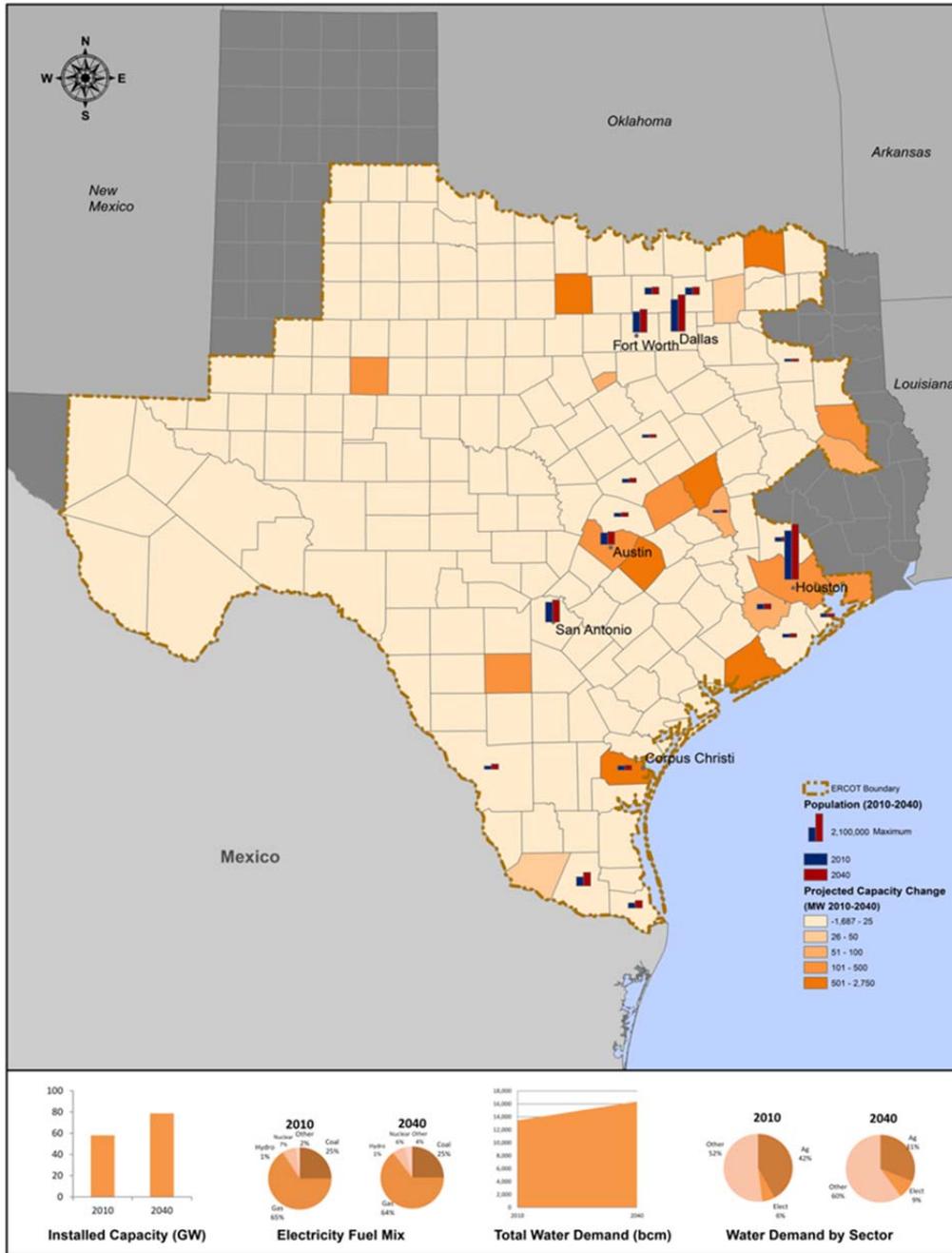
## Case study selection

We selected the ERCOT region as our case study for the U.S. for its

1. size and growth;
2. susceptibility to droughts; and
3. commitment to wind energy.

Figure 34 offers an overview of electricity and population trends for the region.

Figure 34. ERCOT region projected population growth and capacity change by county, 2010–2040



Note: These maps can be found on CNA's website: [www.cna.org](http://www.cna.org)

First, in addition to its large size and energy production capabilities, Texas serves as an important case because its population is predicted to grow significantly, with most of the growth concentrated in the urban areas of Dallas and Fort Worth, Houston, Austin, and San Antonio. Assuming consistent growth rates, Texas's population could grow from its 2010 population of about 25 million to approximately 55 million by 2050, spelling increased competition for water resources from other uses and increased electricity demand.<sup>91</sup> Peak demand is currently projected by ERCOT to grow at 2-3 percent/year during 2013-16, before slowing to roughly 1 percent per year after 2017.<sup>92</sup>

Second, in addition to size, the Texas ERCOT case study was selected because it sits in a region of the U.S. prone to frequent droughts. During the summer of 2011 Texas experienced the worst single-year drought on record that included severe heat and at least 50 days above 100 degrees Fahrenheit in nine cities (see figure 35).<sup>93</sup> As air conditioners strained to cool buildings, demand for electricity set record peak demand figures for days on end, topping 68,000 MW in early August.<sup>94</sup>

During this 2011 drought, EWN liabilities presented themselves numerous times: One thermal plant had to curtail nighttime operations because there was not a sufficient supply of cool water available to bring down the temperature of its discharge. In East Texas, another plant had to pipe in water from a different river source so plants could continue to operate and meet high demand.<sup>95</sup> Heat-induced demand surges, coupled with drought, defines the EWN risks that can only be exacerbated as limited natural water resources face the pressure of increasing demand and severe weather events. Indeed, the Texas Water Resources Board estimated in its *2012 Water for Texas* report that existing water supplies are expected to decline 10 percent by 2060,

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<sup>91</sup>U.S. Census Bureau. "Texas QuickFacts," <http://quickfacts.census.gov/qfd/states/48000.html>. Assuming that Texas's migration rate over the next 40 years will be the same as it was from 2000 to 2010; see Texas State Data Center, "2012 Population Projections by Migration Scenario for Texas," <http://txsdc.utsa.edu/Data/TPEPP/Projections/Data.aspx>.

<sup>92</sup> Electric Reliability Council of Texas, 2013 ERCOT Planning: Long-Term Hourly Peak Demand and Energy Forecast (Austin: ERCOT, 2012).

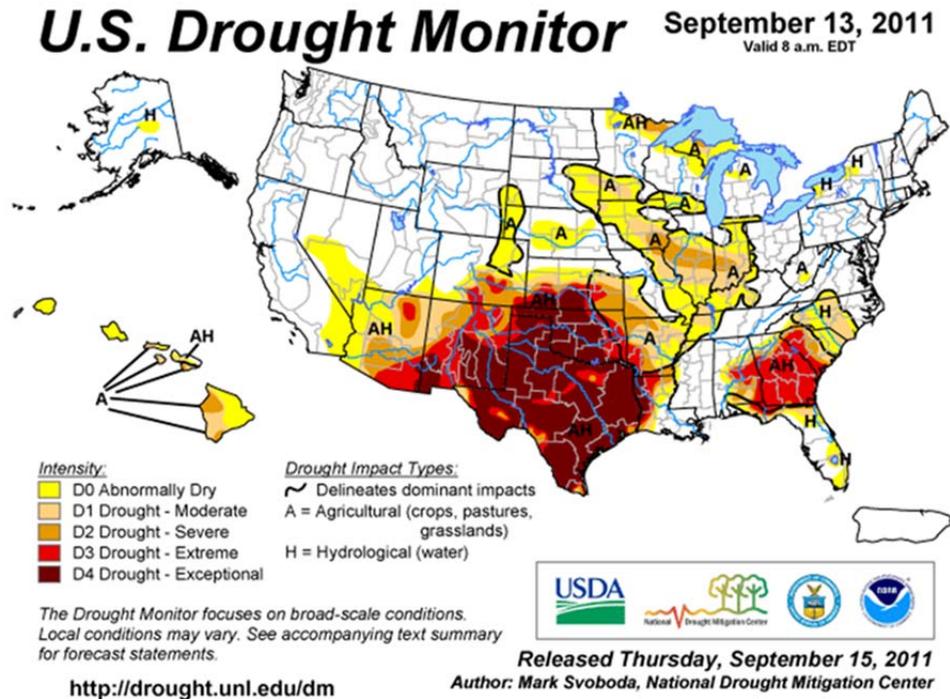
<sup>93</sup> Susan Combs, *The Impact of the 2011 Drought and Beyond*. Publication 96-1704 (Austin: Texas Comptroller of Public Accounts, February 2012), <http://www.window.state.tx.us/specialrpt/drought/>; Chris Dolce and Jonathan Erdman, "Record Heat of 2011," The Weather Channel, updated September 21, 2011, [http://www.weather.com/outlook/weather-news/news/articles/2011-heat-superlatives\\_2011-07-15](http://www.weather.com/outlook/weather-news/news/articles/2011-heat-superlatives_2011-07-15).

<sup>94</sup> Trip Doggett, "ERCOT's Challenges & Opportunities" (presentation for the Texas Public Power Association, August 1, 2012), <http://www.ercot.com/news/presentations/2012>.

<sup>95</sup> "Drought Adds to 2012 Texas Power Supply Worry," Reuters, October 18, 2011, <http://af.reuters.com/article/energyOilNews/idAFN1E79H1L620111018?pageNumber=2&virtualBrandChannel=0>.

while demand for these same resources, fueled by a growing population and economy, is expected to increase.<sup>96</sup> These concerns and others have brought the EWN to the forefront of energy policy planning in the state.

Figure 35. Map of 2011 Texas drought



Third, ERCOT’s electric generation fuel mix is unique in several key ways that help to insulate the state from energy emergencies in times of water scarcity. Unlike the U.S. as a whole, Texas relies to a much lesser degree on coal and nuclear generation, deriving only 33 percent of its electricity from coal and 10 percent from nuclear.<sup>97</sup> Instead, Texas generates 48 percent of its electricity from natural gas, which, particularly for combined-cycle plants, is significantly less water-intensive than coal

<sup>96</sup> Texas Water Development Board, *2012 Water for Texas* (Austin: Texas Water Development Board, January 2012), p. 157.

<sup>97</sup> See EIA Acting Administrator Howard Gruenspecht, “The Future Electricity Fuels Mix: Key Drivers” (presentation for the Electric Power Conference and Exhibition, Baltimore, May 15, 2012), [www.eia.gov/pressroom/presentations/howard\\_05152012.pdf](http://www.eia.gov/pressroom/presentations/howard_05152012.pdf); U.S. Energy Information Administration, “Texas: Profile Overview” and “Texas Net Electricity Generation by Source, November 2013,” State Profile and Energy Estimates, <http://www.eia.gov/beta/state/?sid=TX#tabs-4>.

and nuclear technologies by consumption.<sup>98</sup> This fuel mix profile is important for ensuring the state is in a better position to weather droughts than many others, though its relative economy bears significant exposure to fuel price variability (particularly for natural gas). Notably, Texas had over 10,000 MW of wind capacity as of 2010, which requires no water for operation.<sup>99</sup> Wind potential has hardly been exhausted, and the Texas Public Utility Commission estimates that as much as 25 GW of wind power could have been constructed from 2008 to 2012.<sup>100</sup> This figure is supported by the Union of Concerned Scientists, which has projected that the state could add another 18 GW of wind by 2025.<sup>101</sup> In 2012, Texas added 1,826 MW of wind capacity.<sup>102</sup>

## Modeling analysis of power generation scenarios for ERCOT: 2010–2040

We present the results from five technical and policy scenarios that we tested for the Texas ERCOT region:

### ERCOT Scenarios

1. **The Baseline** scenario, derived from ERCOT reports.
2. **High wind cost**, assuming no decline in the cost of wind turbines over time.
3. **Fixed water availability (WaterLimit)**, limiting water consumption to the amount calculated by the model for the Baseline in 2010.
4. **High end-use efficiency (High-EE)**, assuming a decline of 0.67 percentage point decline per year in demand from the Baseline, and;
5. **A declining carbon cap** that reaches a cut of 40 percent of the Baseline emissions by 2040 (**CO<sub>2</sub>CAP**).

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<sup>98</sup>Mielke, Anandon, and Narayanamurti, Water Consumption of Energy Resource Extraction, Processing, and Conversion, p. 43.

<sup>99</sup> U.S. Energy Information Administration, “Texas Profile Overview,” updated July 2012, <http://www.eia.gov/beta/state/?sid=TX#tabs-4>.

<sup>100</sup> Ibid.

<sup>101</sup> Jeff Deyette and Steve Clemmer, Increasing the Texas Renewable Energy Standard: Economic and Employment Benefits (Cambridge, MA: Union of Concerned Scientists, 2005).

<sup>102</sup> American Wind Energy Association. “Texas Wind Energy,” updated March 6, 2014, <http://www.awea.org/Resources/state.aspx?ItemNumber=5183>.

## Baseline scenario

Figure 36 shows the baseline fuel mix for ERCOT. In 2010, total power generation for the grid that ERCOT controls was 319,000 GWh. The fuel mix at the beginning of the simulation is dominated largely by coal and gas, with roughly a 10 percent share for each wind and nuclear. We used the projection from the 2013 ERCOT Long-Term Hourly Peak Demand and Energy Forecast (ranging to 2022) and extended it by straight-line method to 2040.<sup>103</sup> This method gives us an increase in power demand over the period of 73 percent.

In the Baseline, coal and nuclear generation gradually give way to natural gas and wind, with gas at just over half, and wind at about 40 percent, by the end of the simulation. Both nuclear and coal see a reduction in capacity over the simulation period, ending at roughly 3 percent and 5 percent, respectively. For coal, the factors at work here are largely economic, and for nuclear we assumed no new construction and the retirement of two of the four currently operating plants—one in 2028 and another in 2030, according to their licenses. These retirements account for the bumps in the graphs at those times. We assume that the electric power price of natural gas will stay relatively low, starting at about \$4 per thousand cubic feet (tcf) but increasing by about one-third, similar to EIA's *Annual Energy Outlook 2013* projections.<sup>104</sup> At these prices, natural gas power production is cheaper than coal. While we do assume that regulations prohibit new coal production without CCS, they do not act as a constraint on coal generation due to the relative prices among gas, wind, and coal.

For wind, we used the middle of a range of projections that show the cost of wind generation declining over the period of the simulation. We assumed that wind costs go down by 25 percent between 2010 and 2040. Wind becomes competitive with gas around 2020, and its share in the mix begins to increase. We did not include PV because wind is so dominant.

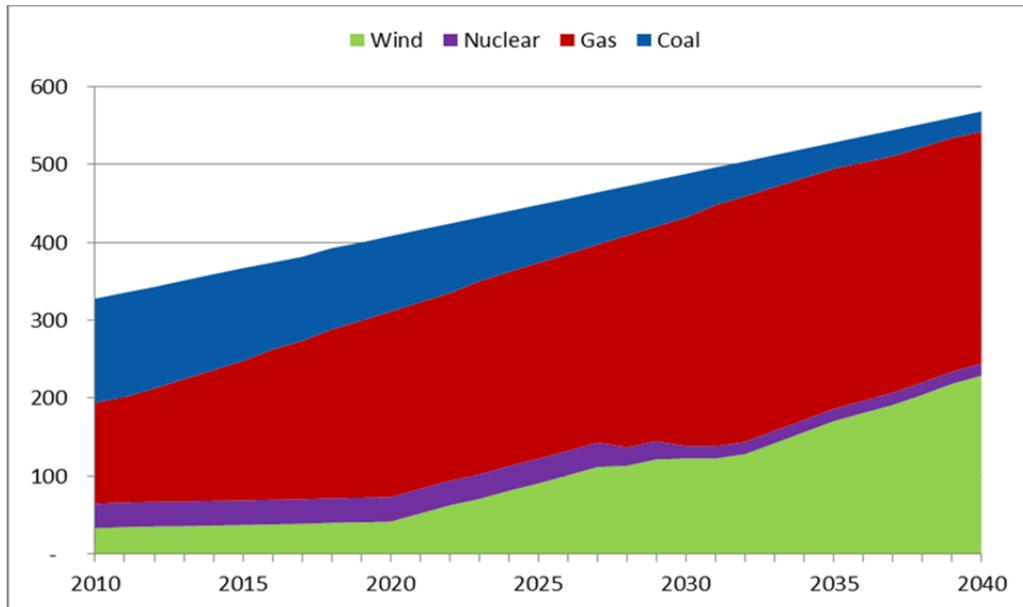
Nuclear generation is constant until the 2028 and 2030 retirement dates, so the share of nuclear in the fuel mix shows a slow decline, a cliff, and then a continuing slow decline as the amount of nuclear generation is diluted by growth.

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<sup>103</sup>. Electric Reliability Council of Texas, 2013 ERCOT Planning: Long-Term Hourly Peak Demand and Energy Forecast, p. 3.

<sup>104</sup>. U.S. Energy Information Administration, *Annual Energy Outlook 2013 with Projections to 2040* (Washington, DC: EIA, April 2013), p. 100.

Figure 36. Baseline power generation fuel mix for ERCOT

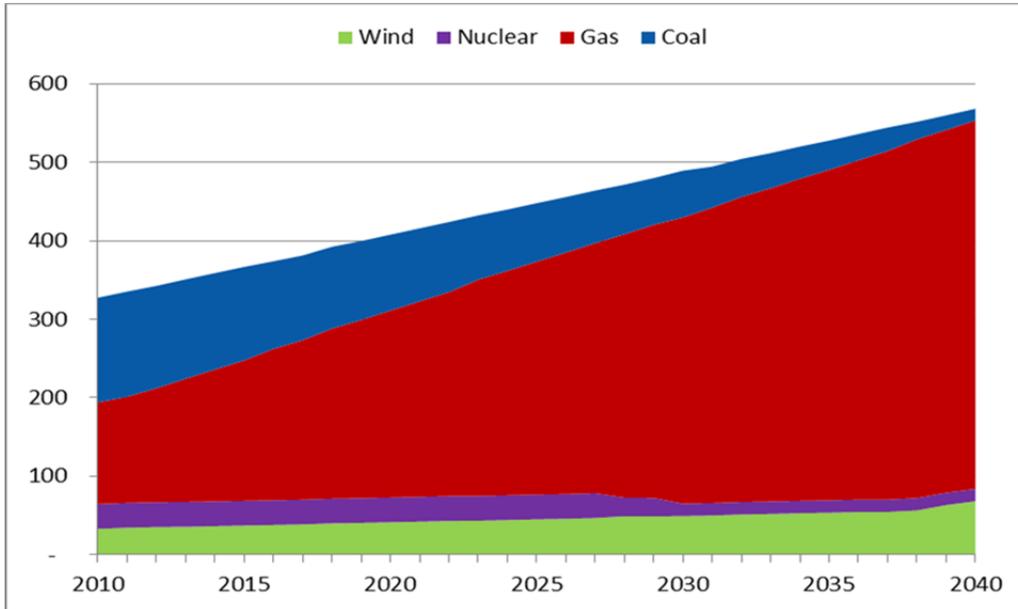


Units = thousand GWh/year

## High Wind Cost

Because wind is becoming so important to power production in Texas, we included a scenario that assumed wind would not play such a critical role. For the High Wind Cost scenario, we assumed that the cost of wind does not come down over time. In this scenario, the power sector gradually becomes almost completely dependent on natural gas, with the shares of coal and nuclear similar to the Baseline, but wind kept at low levels. It will become clear later that wind is key to reducing water use and carbon dioxide emissions in Texas.

Figure 37. High Wind Cost power generation fuel mix

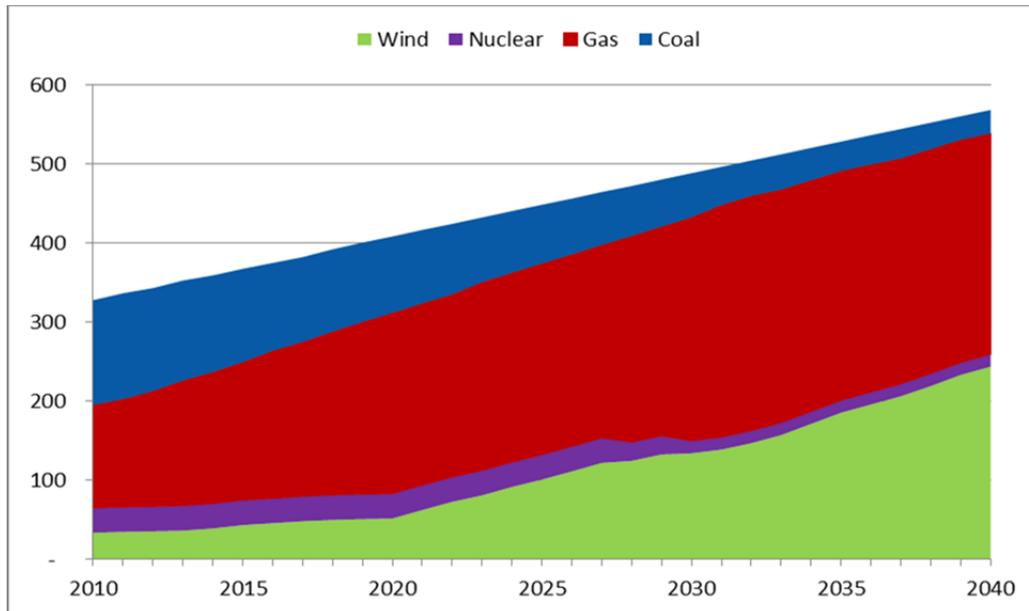


Units = thousand GWh/year

## WaterLimit

The WaterLimit scenario restricts water consumption to the level of the 2010 Baseline. Surprisingly, this has limited impact on the fuel mix compared to the Baseline, with just a few percent more wind and a bit less gas. This trend indicates that although Texas is currently facing drought issues in the power sector, the long-term trends of moving away from coal to gas and wind will keep water demand from growing.

Figure 38. WaterLimit power generation fuel mix

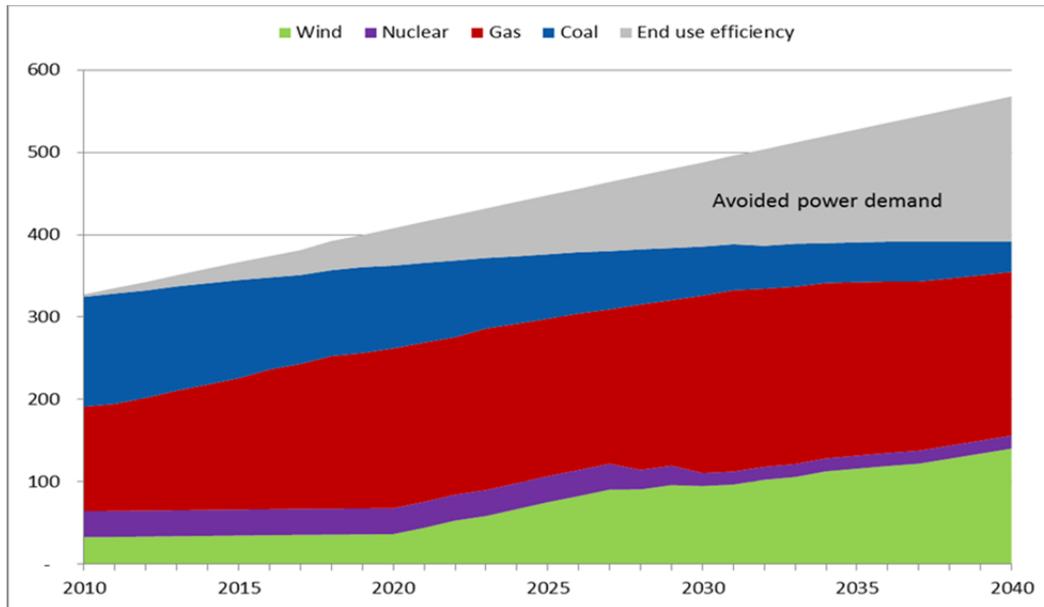


Units = thousand GWh/year

## High-EE

As we saw for the other case studies, energy efficiency suppresses power demand and limits growth in power generation. By 2040, total generation has grown from about 328,000 GWh/year to about 392,000. This is an increase of 17 percent, compared to 73 percent in the Baseline, representing avoided power demand of 176,000 GWh/year. Total capacity in the High-EE case also goes up, but by the smallest amount for the scenarios tested, to about 97,000MW from 82,000MW. In the other scenarios, total generating capacity ends up around 142,000 MW.

Figure 39. High-EE power generation fuel mix

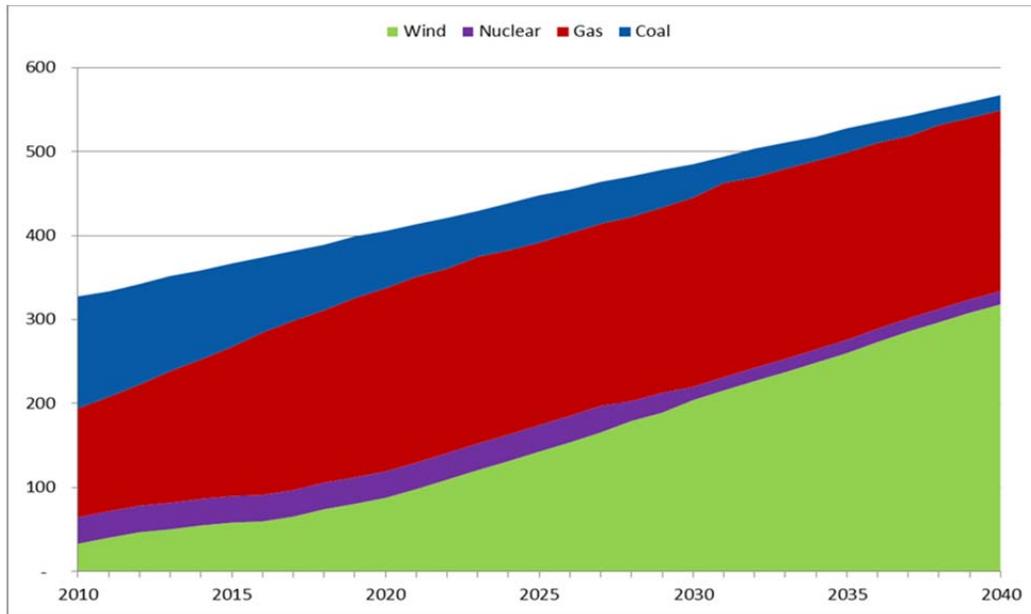


Units = thousand GWh/year

## CO<sub>2</sub>CAP

The carbon dioxide cap in this scenario was assumed to gradually decline beginning immediately in 2010. The cap ultimately declines to 40 percent below the starting value, a level that was determined as the maximum the model could drop. The intent of this exercise was to test the extremes of what might be technically possible in terms of carbon cuts, and to determine what the impacts on other indicators might be. Such a dramatic decline in CO<sub>2</sub> emissions in this scenario produces incredible growth in wind capacity, the only option other than nuclear power able to generate electricity without producing carbon dioxide emissions. This growth in wind comes at the expense of natural gas generation. Coal power makes up only a fraction of the portfolio by 2040, and nuclear capacity reduction follows planned retirements essentially equal to all other scenarios here. We did not include subsidies for wind in our cost assumptions, and the Renewable Portfolio Standard (RPS) was assumed to be 10 percent. Cost subsidies or a higher renewable portfolio standard would also reduce CO<sub>2</sub> emissions and reduce water use.

Figure 40. CO<sub>2</sub> CAP power generation fuel mix



Units = thousand GWh/year

## Cross-scenario comparisons

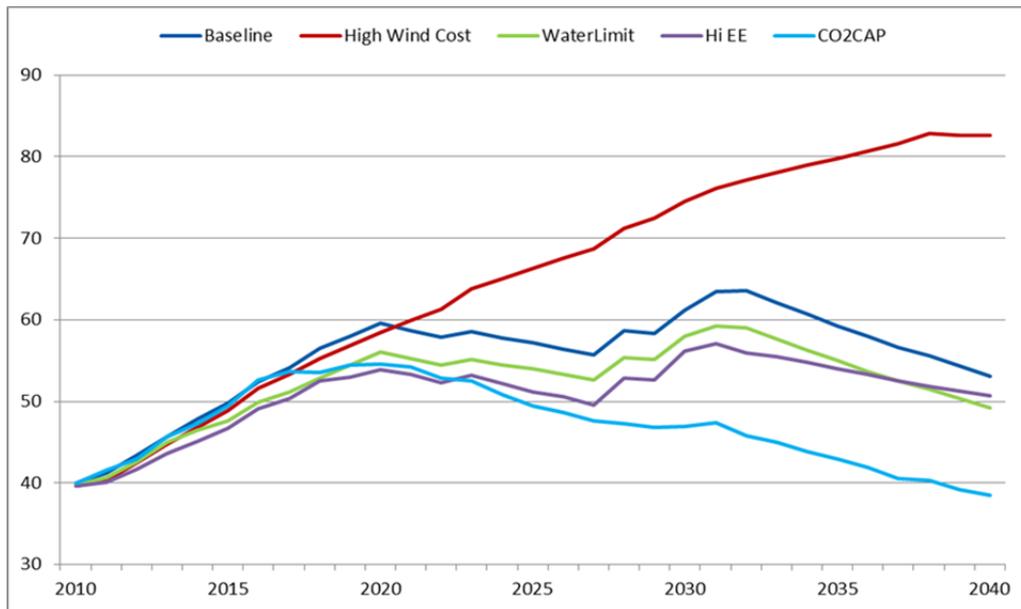
### *Natural gas generation*

In figure 42 we present the modeling results by scenario for power generation from natural gas. For the Baseline, WaterLimit, and High-EE scenarios we see a similar trend. The first increase in gas powered generation comes as coal retires in favor of gas production, and the following decline is due to the increasing competition from wind, as gas plants also retire to be replaced by new gas and wind. The second sharp increase comes as two large nuclear power plants go offline. The final decline is a continuation of the trend toward gas retirements and replacement by wind.

The High Wind Cost and CO<sub>2</sub>CAP scenarios present different outcomes for gas generation. In the High Wind Cost scenario, wind prices remain comparatively high and constant, thus making room for gas to dominate because it is the least expensive option throughout the run. The CO<sub>2</sub>CAP scenario shows the same initial increase in gas, which is followed then by a gradual decline in gas generation as low-carbon wind generation begins to dominate as a result of declining costs and the goal of achieving the CO<sub>2</sub> reduction target of the model. Here we see natural gas acting as a

transitional “bridge fuel,” a relatively new concept that energy planners and officials frequently discuss. The key point here is that for gas to be a bridge, a carbon cap of some form will be necessary.

Figure 41. Share of natural gas in power generation by scenario



Units = %

### *Wind generation*

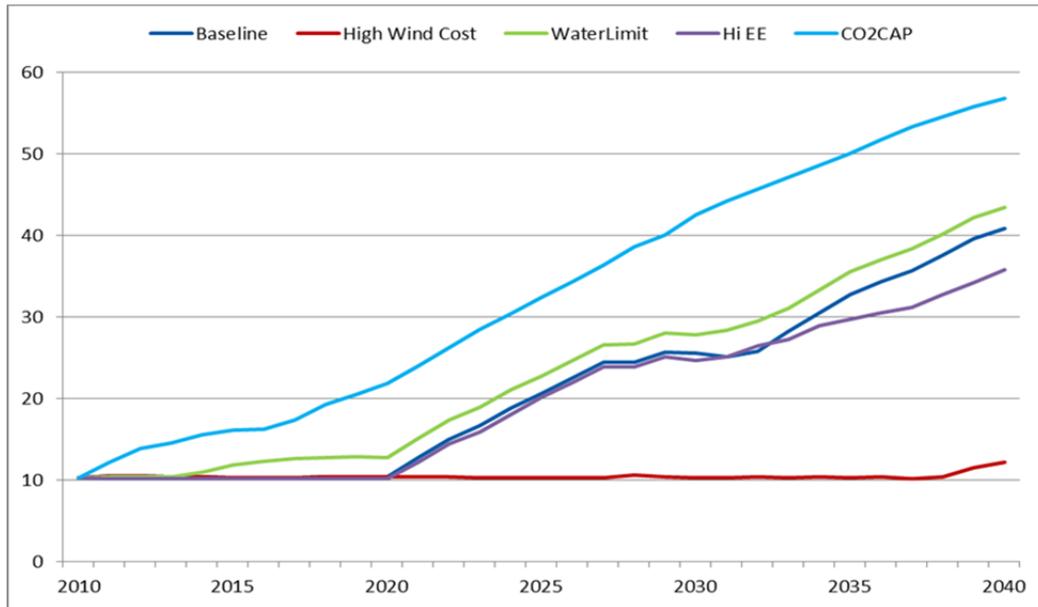
The shares of wind generation in the fuel mix for the scenarios we tested are the complement of the gas-generation shares. While the Baseline, WaterLimit, and High EE scenarios all show similar outcomes, the fastest and strongest wind growth occurs under the CO<sub>2</sub>CAP, initially starting slowly and then showing stronger growth as costs drop. We assume a limit to annual wind generation additions, but we do not assume an upper limit to the share of wind in the mix, or the total amount of wind capacity. For the High Wind Cost scenario, the share of wind remains low, at about 10 percent of total generation, because we assume a minimum amount at that level in the mix (essentially what would be required by a Renewable Portfolio Standard). The wind costs in the model do not include subsidies.

The implications for the shift away from coal and toward more gas and then wind are very substantial for water use in the power sector in ERCOT. Among many other reasons on the fuel side, coal generation requires more water for cooling as a result of its lower overall efficiency, thus producing higher quantities of waste heat per output unit. And, because wind requires no cooling water at all, the move from coal

to gas to wind results in less water consumed by power generation, even though demand is growing.

Currently, ERCOT regularly hits daily wind integration numbers of 20–25 percent.<sup>105</sup> These numbers have gone up dramatically just since 2010, when typical integration numbers were in the 10–12 percent range.<sup>106</sup> Obviously, ERCOT has made great strides in being able to manage the amount of wind on its grid.

Figure 42. Share of wind in power generation



Units = %

### *Water consumption and withdrawal*

Water consumption by scenario is shown in figure 43. For each scenario except High Wind Cost, water consumption goes down substantially. In the Baseline case, consumption goes up slightly for a while, and by 2040 it is down about 27 percent as compared to 2010 levels. After about 2020, when wind becomes competitive, water consumption goes down even in the Baseline. In all cases except High Wind Cost, consumption eventually goes down substantially, despite the fact that once-through cooling is disallowed for new capacity and only recirculating options (which increase

<sup>105</sup>ERCOT, “Wind Integration,” February 2014, <http://www.ercot.com/gridinfo/generation/windintegration/2014/02>.

<sup>106</sup>ERCOT, “Wind Integration,” August 2010, <http://www.ercot.com/gridinfo/generation/windintegration/2010/08>

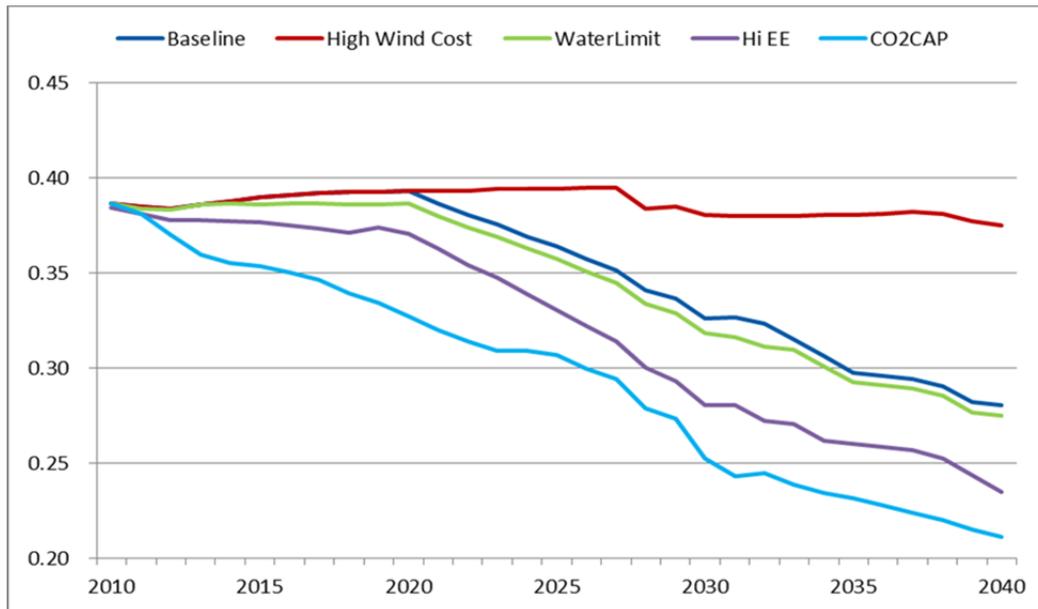
water consumption) are available. These declines are a result of rapidly increasing shares of wind and gas that are displacing coal. Dry cooling is available, but it is not cost-competitive.

In the High Wind Cost scenario, we assume that wind is not economical. However, the shift from coal and nuclear to gas allows water consumption to stay flat, even with substantial growth in capacity. Though significantly reduced as compared with coal, gas still requires cooling water, so the opportunity to reduce water consumption is not available in this scenario.

By encouraging the fastest move away from coal and toward gas and eventually wind, the CO<sub>2</sub>CAP scenario provides the greatest decline in water consumption, about 45 percent by 2040. Notably, the CO<sub>2</sub>CAP scenario advances the benefits of reduced water-consumption forward in time by about a decade as compared to the Baseline. In addition to reducing the vulnerability of the power sector to drought, these declines may have other economic benefits for the region as a water risk hedge and in making water resources available to other sectors of the economy.

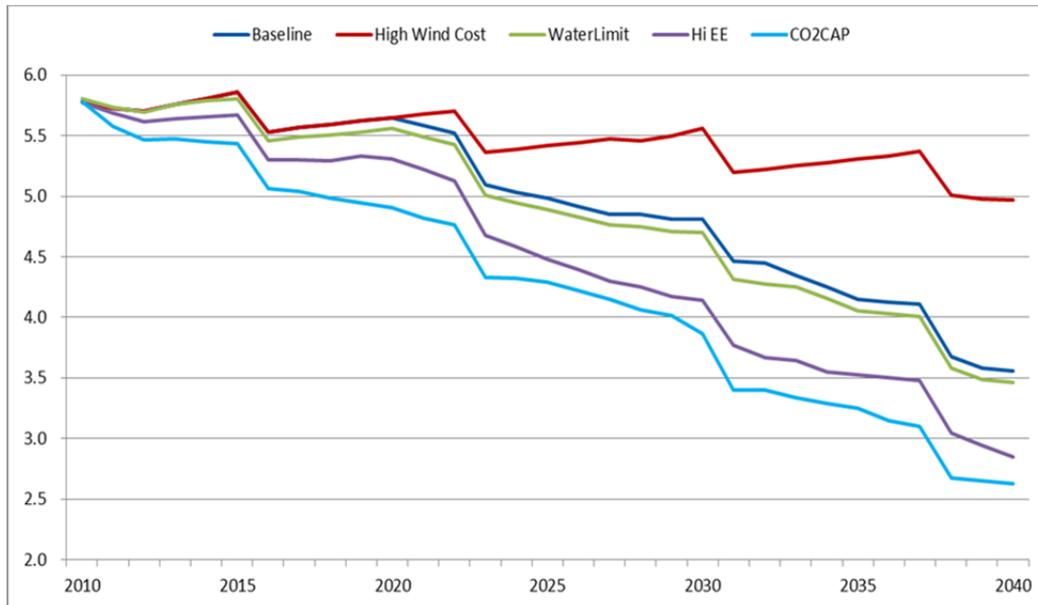
Water withdrawals (figure 44) also decline for each of the scenarios in a pattern similar to water consumption. Withdrawal reductions are lowest again for the High Wind Cost scenario, which relies on a growing gas portfolio and a smaller share of wind generation. The occasional cliffs mark times when a large coal-fired plant retires.

Figure 43. Water consumption by scenario



Units = bcm/year

Figure 44. Water withdrawal by scenario



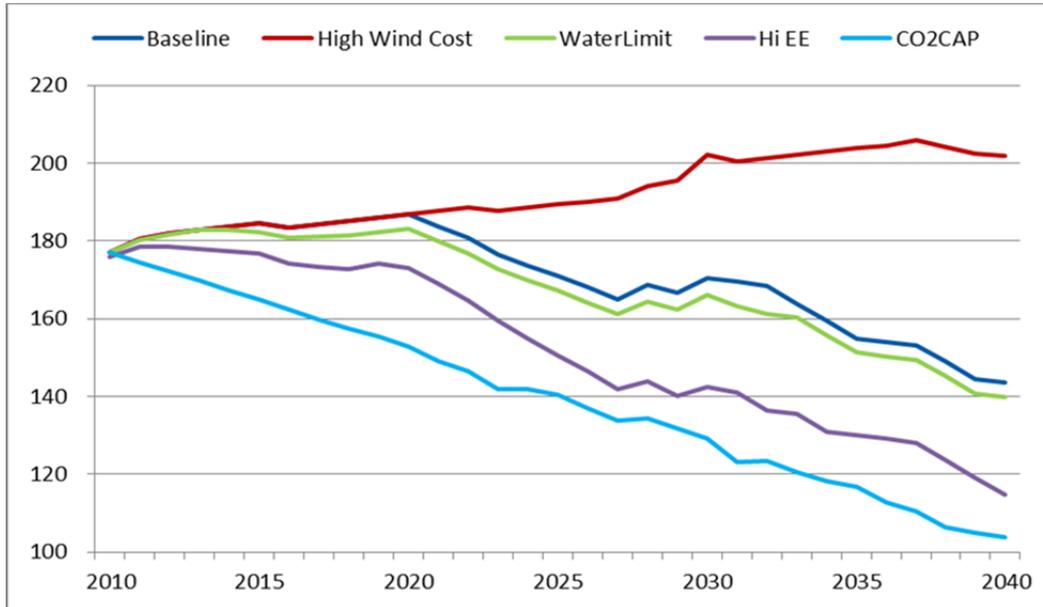
Units = bcm/year

## Emissions

The results for water consumption are strikingly similar to those for CO<sub>2</sub> emissions. In the Baseline, even without a climate mitigation policy in place, emissions go down by about 20 percent over the 30-year period, as coal plants retire and natural gas grows into a much larger share of total generation. The High-EE case by itself yields a drop of more than one-third, while the CO<sub>2</sub>CAP cuts emissions by about 40 percent. If combined with strong demand-side reductions, greater cuts in CO<sub>2</sub> emissions would be possible (see figure 45).

In each of these scenarios, the share of coal-fired generation declines asymptotically to 2040 values of between 3 percent and 9 percent (not shown). As a result, conventional air pollutants—including SO<sub>2</sub>, mercury, NOx, and PM also drop dramatically (by 70–90 percent) as coal use diminishes.

Figure 45. CO<sub>2</sub> emissions

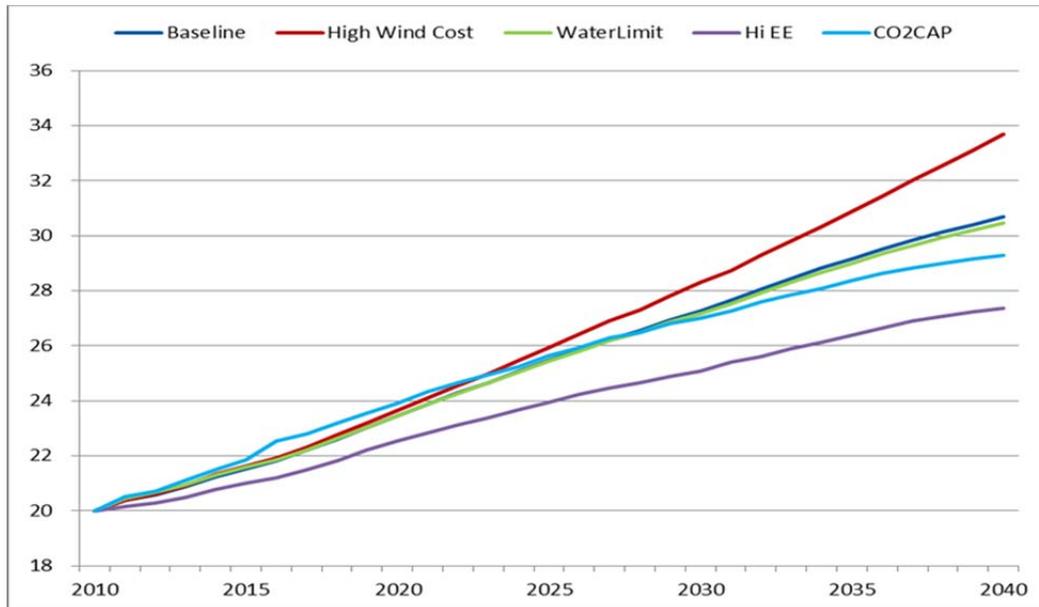


Units = million tons/year

## Costs

The final set of indicators focuses on total, fixed, and variable costs. Total system costs are shown in figure 46. The results for the Baseline, WaterLimit, and CO<sub>2</sub>CAP are roughly the same, while the most notable differences exist between the High Wind Cost and High-EE scenarios. In the High Wind Cost scenario, total system costs are about 10 percent higher, simply because wind generation does not become more cost-competitive over time. For the High-EE case, less generation is required, resulting in 11 percent lower system costs.

Figure 46. Total system costs

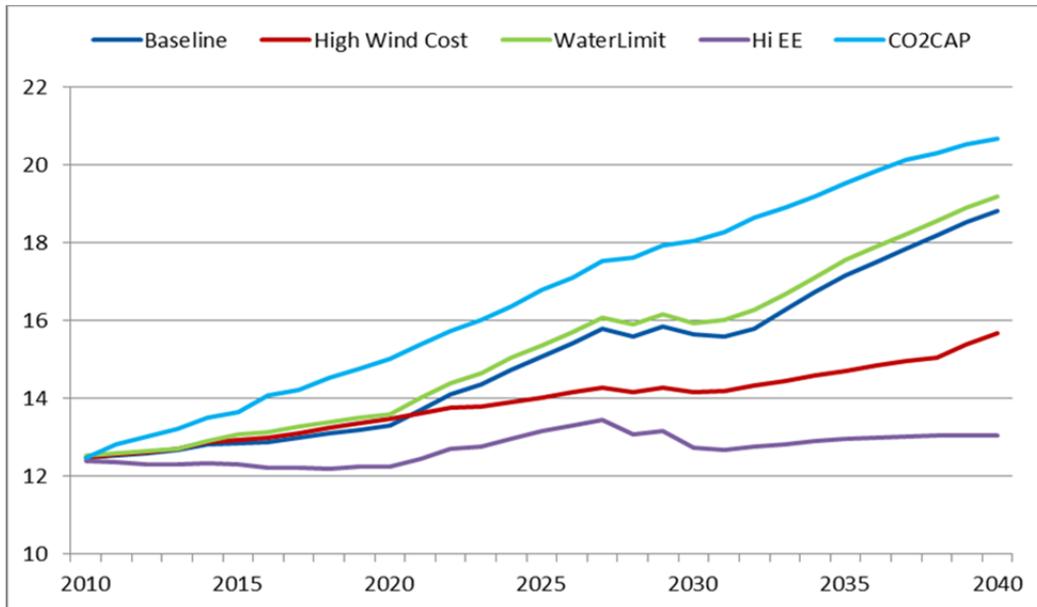


Units = billion U.S.\$/year

While the total system costs show a relatively small range of differences, the fixed and variable costs are quite dramatically different, as shown in figures 47 and 48. Fixed costs are made up of amortized capital costs and fixed operating costs. Wind has the highest fixed costs of the available generating options because the capital costs are relatively high, while in contrast it has the lowest variable cost because there is no fuel cost. Gas has lower capital costs but also has fuel costs to include. As a result, scenarios which generate a high share of wind show the highest fixed costs, with the CO<sub>2</sub>CAP scenario at the top and High-EE at the bottom as a result of its low cost and significant demand reduction over time. As the wind use declines, so do the fixed costs.

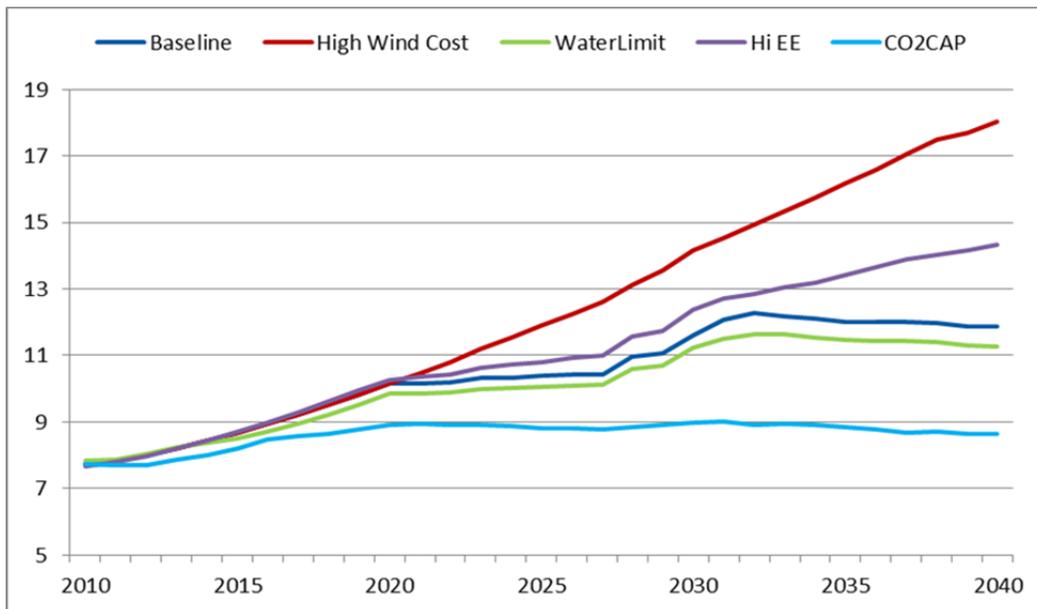
Variable costs comprise fuel, variable O&M costs, and transmission costs, and are nearly the mirror image of the fixed costs, except that High Wind Cost has the highest variable costs, followed by High-EE. CO<sub>2</sub>CAP has the lowest variable costs, which provides an economic advantage of price security by avoiding potential fuel price variability.

Figure 47. Fixed costs



Units = billion U.S.\$/year

Figure 48. Variable costs



Units = billion U.S.\$/year

## ERCOT modeling summary and conclusions

Unlike perhaps any other region covered in this report, the path toward mitigating present and future EWN risks in the ERCOT region looks remarkably similar to that which Texas is naturally best suited. Indeed the state's nation-leading wind generation capacity likely prevented the rolling blackouts that were earnestly close during a difficult 2011 drought, and its significant shale gas resources are already paving an energy path that is less dependent on coal generation's high water requirements. As with other regions that have significant exposure to EWN risks driven by growing demand, an energy future in Texas that is heavily reliant on thirsty thermal generation would leave fewer resources available to other sectors and come at a high cost in the event of a prolonged water shortage or heat event.

In the scenarios explored for this case, Texas's water consumption and withdrawal is expected to decline rather dramatically over the simulation period, provided wind resources are available in the future at declining costs. Texas has made a substantial policy commitment to wind generation through the formation of Competitive Renewable Energy Zones (CREZ), as established by the Texas Public Utility Commission (PUC) and the Texas legislature in 2005, then later officially designated in 2008. This policy mechanism is extremely important for the growth of wind generation in the state, and helps to solve one of the keynote dilemmas of renewable energy: often the best potential is located away from existing transmission infrastructure, discouraging both RE developers from building capacity, and transmission developers from constructing projects without firm customers. According to the most recent quarterly reports of the Texas PUC, the majority of the planned CREZ transmission capacity has now been completed, indicating that Texas is in a strong position to capture its RE resources in significant quantities.<sup>107</sup>

One scenario examined in the model considered the possibility of wind production costs seeing little to no improvement, and found in this case that natural gas would continue rapid growth and supply the vast majority of the fuel mix. Even under this scenario, however, water withdrawal and consumption are not expected to grow with increasing capacity, as coal plants slowly retire in favor of combined-cycle gas plants which are more efficient and thus require less cooling water than a typical coal plant.

As with all cases covered in this report, a reduction in coal capacity is essential to mitigating EWN risk, freeing up water resources and avoiding greater vulnerability. While prevailing economic factors are encouraging a shift to gas under current and forecast cost conditions, a combination of thorough investment in demand-side

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<sup>107</sup>. Competitive Renewable Energy Zone Program Oversight, *CREZ Progress Report No. 13* (Austin: Public Utility Commission of Texas, 2013).

energy efficiency strategies and RE—particularly wind—will offer this region significantly lower EWN risks and provide reduced variable costs and thus more price stability.

One of the most interesting synergies of Texas’s strong policy commitments to enabling growth in both wind capacity and utilization of its significant shale gas resources is that these fuel sources will significantly reduce CO<sub>2</sub> emissions in the state. Ensuring strong net GHG reductions will require careful practice in the recovery of unconventional gas, though this is considered by analysts as technologically feasible at a relatively low marginal cost.<sup>108</sup> As noted elsewhere in this report, hydraulic fracturing to effectively collect shale gas does typically require water and other fluids, but these uses are relatively minimal in comparison to what is needed for cooling thermal plants, and much less than the difference in water requirements between a coal-fired facility and a CCGT plant.<sup>109</sup>

Though Texas’s heavy coal portfolio continues to offer the state somewhat high risk exposure to water resource constraints, a hopeful future exists in light of its significant RE, EE, and gas resources. Continued strong deployment of RE on the supply side and EE on the demand side will offer the most significant benefits to the ERCOT region in the shortest time frame, and likely may offer net economic benefits in the event of a water shortage over the short term.

In spite of the water supply challenges Texas has faced, we find that an energy path founded on strong demand-side investment, and RE and natural gas on the supply side, will enable Texas to meet long-term growth in energy demand while yet reducing water withdrawals, consumption, and emissions in the power sector below even 2010 levels at the lowest total cost. Least-cost generation, emissions reductions, and water use reductions are all virtually proportional to the speed at which coal use is phased out and demand is supplied through EE, RE, and natural gas. Due to the strong connection between the accelerated phase-out of coal power and all of Texas’s energy goals—including air quality and climate benefits—this report also recommends that the state impose a moratorium on new coal generation to lock in these gains.

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<sup>108</sup>. International Energy Agency, *World Energy Outlook 2011: Are We Entering the Golden Age of Gas?* Special Report (Paris: OECD/IEA: 2011), [http://www.worldenergyoutlook.org/media/weowebbsite/2011/WEO2011\\_GoldenAgeofGasReport.pdf](http://www.worldenergyoutlook.org/media/weowebbsite/2011/WEO2011_GoldenAgeofGasReport.pdf).

<sup>109</sup>. Emily A. Grubert, Fred C. Beach, and Michael E. Webber, “Can Switching Fuels Save Water? A Life Cycle Quantification of Freshwater Consumption for Texas Coal- and Natural Gas-Fired Electricity,” *Environmental Research Letters* 7, no. 4 (2012): 045801.

# Appendix

## The CNA Electricity-Water Model

The Electricity-Water Nexus model is a mixed-integer linear programming model that seeks to meet the specified electric power demand at least cost. Mixed-integer linear programming means that part of the model solution can only be in whole numbers—in this case, the number of power plants. The model simulates new construction, retirement due to aging, and early retirements due to cost-ineffectiveness.

## Power plant types defined in the model

We constructed the model to meet power demand for each year of the simulation by choosing from a set of representative power plants that include six options for fuel—three thermal (coal, natural gas, and nuclear) and three renewable (hydro, wind, and PV). It also has three combustion options for coal (conventional/sub-critical and advanced/super-critical, without and with carbon dioxide capture and sequestration, or CCS), three combustion options for gas (conventional and combined cycle, without and with CCS), and three cooling options for the thermal plants (once-through, recirculating, and dry). The next two lines below show the code from the model that declares these options in a set named CT; below that are the definitions.

*CT Combustion Technologies / CONV\_COAL, CONV\_GAS, CONV\_NUKE,  
ADV\_COAL, ADV\_COAL\_CCS, NGCC, NGCC\_CCS, HYDRO, WIND, PV;* (1)

- CONV\_COAL, conventional/subcritical coal
- CONV\_GAS, conventional gas
- CONV\_NUKE, conventional nuclear
- ADV\_COAL, advanced/supercritical coal
- ADV\_COAL\_CCS, advanced/supercritical coal with carbon capture and sequestration
- NGCC, natural gas combined cycle
- NGCC\_CCS, natural gas combined cycle with carbon capture and sequestration
- HYDRO, hydroelectric
- WIND, wind

- PV, photovoltaic.

## Declared characteristics for each technology

For each representative power plant, we defined a set of characteristics for cost, generation, and environmental performance. These characteristics include fixed and variable costs; generation capacity; capacity factor (the percent of time the plant can run); water withdrawal and consumption; and emissions of nitrogen oxides (NOx), mercury, sulfur dioxide (SO<sub>2</sub>), particulate matter (PM), and carbon dioxide (CO<sub>2</sub>). Fixed costs include amortized capital costs and fixed operating costs. Variable costs include variable operation and maintenance costs including fuel, and power transmission costs. Sets are shown below.

### Cost components

$$\begin{aligned}
 & \text{COSTS } \textit{Power cost components} \text{---} \\
 & \textit{/VarOM, Fuel, FixedOM, AmortCap / ;}
 \end{aligned}
 \tag{2}$$

Where

- VarOM, variable operation and maintenance cost,
- Fuel, fuel cost,
- FixedOM, fixed operating and maintenance cost,
- AmortCap, amortized capital cost.

### Cooling types

$$\text{COOL } \textit{Cooling Technologies / OT, REC, DRY, NA / ;}
 \tag{3}$$

Where:

- OT, once-through or open-loop cooling,
- REC, recirculating or closed-loop cooling,
- DRY, dry cooling,
- NA, not applicable -- no cooling required.

## Environmental information

$$\frac{TC \text{ Technology Characteristics}}{WTR\_WTHDRW, WTR\_CONSUM, HG, PM2\_5, SO2, NOx, CO2} ; \quad (4)$$

Where:

- WTR\_WTHDRW, water withdrawal, m3/MWh
- WTR\_CONSUM, water consumption, m3/MWh
- HG, mercury emissions, kg/MWh
- PM2\_5, particulate matter below 2.5 microns, kg/MWh,
- SO2, sulfur dioxide, kg/MWh
- NOx, nitrous dioxide, kg/MWh
- CO2, carbon dioxide, kg/MWh.

Demand projections come from official published sources, case-by-case. Cost data come from the Energy Information Administration (EIA)<sup>110</sup>, water withdrawal and consumption data come from the National Renewal Energy Laboratory (NREL)<sup>111</sup>, and environmental data come from the National Energy Technology Laboratory (NETL). Assumptions about the future costs and performance of renewable power come from a variety of sources, including NREL.

For each case, we developed a baseline that is a reproduction of a projection from some other published source(s); we did not independently develop baseline demand projections. The baseline defines the annual demand, the fuel mix and how it changes over time, the starting fleet of power plants, and the starting policy conditions. The baseline gives us an initial point of comparison and a jumping-off point to develop other scenarios.

The starting power plant options and numbers for each case study were determined by the existing fleet in each region.

<sup>110</sup> EIA, “Levelized Cost and Levelized Avoided Cost of New Generation Resources in the Annual Energy Outlook 2014.” [http://www.eia.gov/forecasts/aeo/pdf/electricity\\_generation.pdf](http://www.eia.gov/forecasts/aeo/pdf/electricity_generation.pdf)

<sup>111</sup> Macknick, R. Newmark, G. Heath, and K.C. Hallett, *A Review of Operational Water Consumption and Withdrawal Factors for Electricity Generating Technologies*. Technical Report NREL/TP-6A20-50900 (Golden, CO: National Renewable Energy Laboratory, March 2011).

## The objective function

The model produces a solution by finding the lowest total system cost, subject to various combinations of constraints. *TSysCost*, the objective function, is the equation that defines total system cost:

$$TSysCost.. SYSCOST = e = VARCOST + FXDCOST ; \quad (5)$$

Where:

- SYSCOST is the total system cost,
- VARCOST is a variable that is the sum of the variable costs,
- FXDCOST is a variable that is the sum of the fixed costs.
- VarCostCalc is the variable cost calculation.

$$\begin{aligned} VarCostCalc..VARCOST = e = \\ (sum((CT,COOL),(PCOSTS(CT,COOL,"VarOM") \\ + PCOSTS(CT,COOL,"Fuel")) * Plants(CT,COOL) \\ * PlantSz(CT,COOL) * CapFact(CT,COOL) * 365 * 24)); \end{aligned} \quad (6)$$

Variable costs are equal to the sum of the variable operating costs plus the fuel costs for all plants by combustion technology and cooling type (PCOSTS), multiplied by the number of plants of each type (Plants), the plant size (PlantSz) and the capacity factor (CapFact), which is the fraction of the time a plant operates, multiplied by the number of hours in a year. The capacity factor can be adjusted over time to represent technology gains.

FxdCostCalc is the calculation for fixed costs, which are the fixed operation and maintenance costs plus the amortized capital costs, multiplied by the number of plants and the plant size for each combustion and cooling technology.

$$\begin{aligned} FxdCostCalc..FXDCOST = e = \\ (sum((CT,COOL),(PCOSTS(CT,COOL,"FixedOM") + \\ PCOSTS(CT,COOL,"AmortCap")) * Plants(CT,COOL) * \\ PlantSz(CT,COOL)); \end{aligned} \quad (7)$$

In these calculations, the model finds the optimal, i.e. least cost solution for SYSCOST, by solving for the combination of plants that meets the current year demand while satisfying other constraints that may be imposed. The variable "Plants" is defined to be a positive integer. Each category of costs can be changed by inflating or deflating them over the course of a 30-year run.

Demand is determined by the annual demand requirement (AnnDemReq) equation given below, where the current year's power demand (PwrDem) must be less than or

equal to the sum of the product of the number of plants in each category multiplied by the average plant size, the capacity factor, and the number of hours in a year.

$$AnnDemReq.. PwrDem = l = \sum((CT, COOL), Plants(CT, COOL) * PlantSz(CT, COOL) * CapFact(CT, COOL) * 365 * 24); \quad (8)$$

## Determining the number of plants

The number of plants is defined by the identity:

$$PlantIdent(CT, COOL).. Plants(CT, COOL) = e = \begin{aligned} &PriorPlants(CT, COOL) \\ &+ PlantsBuilt(CT, COOL) \\ &- PlantsRetrd(CT, COOL) \\ &- SchedRet(CT, COOL); \end{aligned} \quad (9)$$

Where:

- PriorPlants is the number of plants from the prior year's solution,
- PlantsBuilt is the number of plants built during the current year's solve,
- PlantsRetrd is the number of plants retired beyond those scheduled, and
- SchedRet is the number of plants scheduled to be retired, determined by the starting number of plants and their average age.

We assumed average ages for each fuel type across all the cases.

These variables are subject to several constraints which keep the model from producing negative numbers and keep the model from producing large swings in outcomes from year to year:

- PlantsBuilt is an integer number that cannot be negative,
- PlantsBuilt cannot be larger than the maximum number of new plants allowed by type, which is determined during the calibration process,
- PlantsBuilt defines the plants types that are not allowed, for example by regulation,
- PlantsRetrd is an integer number that cannot be negative,
- PlantsRetrd cannot be larger than the maximum number of plant retirements allowed by type,
- PlantsRetrd cannot be larger than the number of existing plants by type,
- The model must maintain a minimum ratio between generation and generating capacity as established by the baseline.

## Scenario management

Scenarios are managed by a combination of multipliers, constraints, and plant type selection. Multipliers are managed in Excel. An example is given in Table A1, which shows power demand for a selection of years for the baseline and a high energy efficiency (HiEE) scenario. The HiEE scenario cuts annual demand growth from 4.88 percent per year to 3.88 percent per year, or twelve percent by the end of the scenario. Fuel prices, carbon caps, and capacity factors are also managed using multipliers, as shown in column 4 of the table.<sup>112</sup>

Table 6. Power demand for two scenarios by year

Year	Baseline Energy Demand	Demand Multiplier	% growth by 2040	Efficiency Scenario	Efficiency Multiplier	% effic by 2040
2010	1,199,784	1.0000	147%	1,199,784	1.0000	
2011	1,258,333	1.0488	<b>annual % change</b>	1,246,336	1.0388	<b>annual % change</b>
2012	1,316,883	1.0976	4.88%	1,292,887	1.0776	3.88%
2013	1,375,432	1.1464		1,339,439	1.1164	
2014	1,433,982	1.1952		1,385,991	1.1552	
2015	1,492,531	1.2440		1,432,542	1.1940	
.	.	.		.	.	
.	.	.		.	.	
.	.	.		.	.	
2038	2,839,169	2.3664		2,503,229	2.0864	
2039	2,897,718	2.4152		2,549,781	2.1252	
2040	2,956,268	2.4640		2,596,333	2.1640	

Various scenarios are managed by defining a limit which serves as a floor or ceiling. For example, the equation WTRConSys, total system water consumption, is the equation that defines the water consumption limit for the WaterLimit scenarios. In this example, InitWaterConsum is the amount of water consumption calculated for 2010, the first simulation year. The sum of the product of power generation multiplied by the technical characteristic (TC) that defines amount of water consumption per MWh (WTR\_CONSUM) for each plant type must be no greater than the water consumption at the beginning of the run.

$$\begin{aligned}
 WTRConSys.. \text{InitWaterConsum} = g = & \\
 & \text{sum}((CT, COOL), (Plants(CT, COOL) \\
 & * PlantSz(CT, COOL) * CapFact(CT, COOL) * 365 \\
 & * 24 * TC(CT, COOL, "WTR_CONSUM")); \quad (10)
 \end{aligned}$$

Other scenarios that also use this form include carbon caps (with annual multiplier), renewable portfolio standard, water withdrawal constraint, and fuel mix limits.

<sup>112</sup> The middle years of the table, from 2016 to 2037 are not shown.

The third way to develop scenarios with the model is to include or exclude certain types of model plants. Tables 7, 8, and 9 show two ways to do this. To come into the solution for a run, the plant type must have both a size and an initial number of plants. In the example below, advanced coal with Adv\_Coal\_CCS/REC (advanced coal with CCS and recirculating cooling, sized at 621 MW capacity) and NGCC/Dry (natural gas combined cycle turbine with dry cooling, sized at 320 MW capacity) have just one plant each in the initial fleet, meaning that they can be used later in the solve, even though at the start their generation is inconsequential. In contrast, PV has no initial number and cannot come into the solution, even though it has a capacity value associated with it. The sum of the product of plant size and initial plants is the starting value for generating capacity.

Table 7. Power plant fleet initialization A

Plant size	MW			
	OT	REC	Dry	NA
Conv_Coal	320	320	320	
Adv_Coal	621	621	621	
Adv_Coal_CCS		621	621	
Conv_Nuke				
NGCC		320	320	
Hydro				
Wind				100
PV				50

Table 8. Power plant fleet initialization B

InitPlants	#			
	OT	REC	Dry	NA
Conv_Coal	148	182	41	
Adv_Coal	77	93	21	
Adv_Coal_CCS		1	1	
Conv_Nuke				
NGCC		4	1	
Hydro				
Wind				77
PV				

Plant categories can also be excluded from being built even if they are in the initial fleet. This is managed by selecting the types to be excluded in the Build Restriction table, shown as table A3. Any plant type with the number one in its cell will not be

built. In the example shown, the values in the table restrict any new conventional coal of any cooling type, and any advanced coal that uses once-through cooling

Table 9. The Build Restriction table keeps plant types from being built

Build Restriction				
	OT	REC	Dry	NA
Conv_Coal	1	1	1	
Adv_Coal	1			
Adv_Coal_CCS				
Conv_Nuke				
NGCC				
Hydro				
Wind				
PV				

### *Running the model*

The GAMS software we use to run the model defines the term “model” to mean a specific set of equations. In this sense, many models can be defined for a wide variety of purposes from the selection of defined equations. A model to test a water limit scenario follows:

$$\begin{aligned}
 & \text{model WTRCONLIM} / \text{TSysCost}, \text{FxdCostCalc}, \text{VarCostCalc}, \\
 & \text{AnnDemReqT}, \text{PCapReq}, \text{PlantIdent}, \text{PlantRLim}, \text{PlantBLim}, \text{MaxPlantsB}, \\
 & \text{WTRConSys} / ;
 \end{aligned}
 \tag{11}$$

Where the model WTRCONLIM is defined by the following equations:

- TSysCost, total system cost -- the objective function,
- FxdCostCalc, fixed cost calculation,
- VarCostCalc, variable cost calculation,
- AnnDemReq, annual demand requirement,
- PCapReq, peak capacity requirement -- maintains ratio between generation and capacity,
- PlantIdent, plant identity,
- PlantRLim, plant retirement limit,
- PlantBLim, plant building restriction (see Table 3),
- MaxPlantsB, maximum plants built -- limits new construction by plant type,
- WTRConSys, system water consumption constraint.

To run the WTRCONLIM model using mixed-integer linear programming, the instruction is:

*solve WTRCONLIM using mip minimizing SYSCOST ;* (12)

### *Strengths and weaknesses*

Here we review some key attributes of the model and comment on how these strengthen the model or limit its utility.

Size. The model was built to support scoping exercises and therefore was kept fairly small and aggregated. The model represents a single region, so there is no regional detail represented in the input data or the results. This level of aggregation has an advantage in that it limits the data requirements and simplifies calibration.

Water accounting. The key advantage of this model is that it accounts for water withdrawals and consumption used in thermal cooling. For this reason, it enables a broader perspective on the environmental impact of electric power generation. The model does not capture water availability and water resource competition between sectors, however. We intend to extend the model in this way in our next iteration of this work.

Approach. The programming approach we used to develop the model, mixed-integer linear programming, is commonly used by energy economists to represent the electric power sector. In this way, the approach does not stray from well-developed techniques used in this field of study. We did feel the need to develop a new model rather than adapt an existing one however, which makes the model more of a black box.





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