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Unused Turbines, Ample Gas Supply, and PV to Solve RPS Issues?

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Nationwide deployment of cost-competitive distributed PV (photovoltaic)1 to meet peaking and load-following demand, following the distributed PV scenario evaluated in California to meet the state's renewable portfolio standard (RPS) target of 33 percent by 2020, could displace on the order of 10 billion cubic feet a day of natural gas demand. Were this same approach followed nationwide, the quantity of natural gas consumption displaced by this level of distributed PV deployment, in terms of barrels of oil equivalent (BOE), would be greater than current U.S. crude oil imports from the Persian Gulf.

Were this same approach followed nationwide, the quantity of natural gas consumption displaced, in BOE, would be greater than current U.S. crude oil imports from the Persian Gulf.

Increasingly abundant supply and static demand have resulted in a precipitous decline in U.S. natural gas prices. Displacement of peaking gas turbine generation with distributed PV would create further downward pressure on domestic natural gas demand. These developments could, with appropriate regulatory structure, contribute to assuring predictably cost-competitive natural gas prices for the foreseeable future.

The United States has over 200,000 megawatts of largely underused, high-efficiency, natural gas–fired combined-cycle plants. The reason for low utilization of these plants has been the relatively high cost of natural gas relative to coal in recent years. Predictably competitive natural gas prices would likely result in much higher utilization rates of the U.S. fleet of base-load natural gas–fired combined-cycle plants.

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In turn, this strategy could contribute to permanent displacement and retirement of a large portion of the U.S. coal-fired power plant fleet on economic grounds alone. Approximately 80 percent of U.S. coal plants are at 30 or more years old, and nearly 50 percent are 40 or more years old. These plants are at or near the end of their design operational lifetimes. The relative abundance of domestic natural gas and the potential of distributed PV to progressively displace a large portion of peaking and load-following natural gas demand provide the United States with a strategic opportunity to phase out much of the current stock of base-load coal-fired generation with little negative economic impact on electricity consumers.

The relative abundance of domestic natural gas, and the potential of distributed PV, provide the

United States with a strategic opportunity to phase out much of the current stock of base-load coal-fired generation.

The climate-change benefits of such a strategy would be tremendous, far beyond what is currently contemplated in the current round of federal climate legislation or state RPS requirements. Base-load natural gas combined-cycle plants emit about 60 percent less carbon dioxide per megawatt-hour than coal plants. Operating the nation's inventory of over 200,000 megawatts of base-load combined-cycle plants as designed, as base-load electric generation plants that displace coal plant capacity, would reduce greenhouse gas emissions from U.S. electric power generation by more than 20 percent. This reduction would be added to the 20-percent reduction achieved by displacing much of the current gas-fired peaking and load-following capacity with distributed PV generation. Finally, the significant amount of U.S. wind generation contributes additional greenhouse gas reduction benefits.

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CURRENT PV COSTS OPEN DOORS

State-of-the-art PV cost of energy (COE) is competitive with peaking gas turbine COE, even at natural gas prices in the $4-a-million-Btu range.2 However, PV does not function as a true peaking resource limited to a few hundred hours a year of operation. PV inherently operates as a load-following resource, with an annual capacity factor in the range of 18 to 20 percent.

California regulators have studied a scenario where the gap between the state's current renewable energy generation rate of approximately 11 percent and the 2020 target of 33 percent is met with approximately 27,500 megawatts of distributed photovoltaic (PV) solar power. This equates to 50,000 to 60,000 gigawatt-hours a year of PV generation in the 250,000-gigawatt-hour-a-year California electricity market. This 50,000 gigawatt-hours of avoided natural gas-fired generation is equivalent to approximately 70 million BOE of avoided fossil energy consumption.3

Navigant estimates that California has more than 80,000 megawatts of combined commercial and residential rooftop PV potential.4 Adding in commercial parking lot PV potential would bring this total to well over 100,000 megawatts.5 There is no question that there is sufficient PV potential on existing structures and commercial parking lots to develop 27,500 megawatts of distributed PV in the state.

In addition to California, many states have established renewable portfolio standards requiring that renewable energy sources provide as much as 25 percent of electric power generation by 2020 or earlier.6 Distributed rooftop and parking lot PV has the resource potential to play a major role in meeting these RPS requirements on a national level. The Navigant

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study estimated the combined nationwide commercial and residential rooftop PV potential at over 700,000 megawatts. This potential exceeds a million megawatts when commercial parking lot potential is added to the total.

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PV is inherently a peaking and load-following source. PV produces power only during daylight hours when electric loads are higher. This capacity is reliably available during peak summertime demand periods, which occur on hot sunny days. Distributed PV power is inherently displacing relatively high-cost conventional peaking and load-following generation resources.

For this reason and others (importantly, that distributed PV requires little to no transmission investment), distributed PV should be prioritized over renewable resources that provide only bulk energy and little or no reliable capacity. Onshore wind resources generally fall into this later category. The relationship between electricity demand and distributed PV and onshore wind output is shown in Exhibit 1.

SAYONARA TO THE STRAITS Of HORMUZ?

The nation has an annual electricity generation rate of approximately 4 million gigawatt-hours a year.7 Extrapolating the California distributed PV scenario to the nation as a whole as the preferred strategy for meeting RPS requirements, such that approximately 20 percent of the nation's electricity supply is generated by distributed PV, equals about 800,000 gigawatt-hours a year of distributed PV with a nameplate capacity of over 400,000 megawatts. The objectives of this preferred RPS strategy would be:

(1) to displace peaking and load-following gas turbine generation with PV generation and (2) displace a large amount of base-load coal-fired generation with base-load combined-cycle natural gas generation. Displacing peaking/load-following gas turbine output with cost-competitive distributed PV would make available more North American natural gas in BOE than all of the crude oil the United States currently imports from the Persian Gulf.

This 800,000 gigawatt-hours of avoided natural gas–fired generation is equivalent to approximately 1,000 million BOE of avoided fossil energy consumption. The United States imported approximately 850 million barrels of oil from the Persian Gulf in 2008.8 Displacing peaking/load-following gas turbine output with cost-competitive distributed PV would make available for other uses more North American natural gas in BOE than all of the crude oil the United States currently imports from the Persian Gulf.

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exhibit 1. PV and Onshore Wind Summertime Output vs. Demand—San Diego / DOI 10.1002/gas

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The addition of over 400,000 megawatts of distributed PV over the next decade may appear an impossibly ambitious target. However, worldwide PV manufacturing capacity should reach approximately 30,000 megawatts a year in 2010, and the sector has demonstrated the capability to quickly expand production.9 The U.S. electric power industry has also recently demonstrated the ability to add a tremendous amount of generating capacity in a short period of time. Approximately 200,000 megawatts of new gas turbine capacity was built in the five-year period 2000–2004 (Exhibit 2).

TURBINES TO SUPPLANT COAL PLANTS STAND READY AND UNUSED

The driver behind the combined-cycle component of the gas turbine construction boom was the premise that natural gas prices would remain low indefinitely and, therefore, natural gas–fired combined-cycle plants would produce lower-cost electricity than coal plants. However, from 2002 to 2008, natural gas prices marched steadily upward. This drove up the COE of the base-load combined-cycle plants and negatively impacted the cost-competitiveness of combined-cycle generation compared to coal plant generation. The collective capacity factor of base-load combined-cycle plants has been relatively low for years as a result of this relative lack of cost-competitiveness.

For example, the composite capacity factor of the 90,000 megawatts of gas turbine capacity in the South Atlantic region in 2008 was 11 percent compared to more than 62 percent for coal generation.10 Approximately 50,000 megawatts of this gas turbine capacity consists of base-load combined-cycle units. The South Atlantic region has a base-load demand of approximately 50,000 megawatts.

Natural gas prices have dropped precipitously since the summer of 2008 due to the economic slowdown and attendant reduction in natural gas demand and steadily rising domestic production for unconventional gas resources. The Henry Hub spot natural gas price averaged less $3.50 a million Btu's in July 2009. The Energy Information Administration projects that at a delivered price of $3.50 a million Btu's, on a price basis alone the capacity factors of combined-cycle plants and coal plants in the South Atlantic region should reverse. The capacity factor of the combined-cycle natural gas units would increase to approximately 80 percent, with a concomitant decrease in the capacity factor of the coal plants.11

The United States has about 350,000 megawatts of coal plant capacity, of which 300,000 megawatts are over 30 years old. Exhibit 3 addresses the U.S. coal plant inventory as of the year 2000. Less than 5,000 megawatts of

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exhibit 2. U.S. Gas Turbine Capacity Additions Since 1998
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exhibit 3. Age Distribution of U.S. Coal Plant Inventory

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new U.S. coal capacity were added from 2000 through 2007.12

The effect of cost-competitive natural gas on greenhouse gas emissions is potentially dramatic. Exhibit 4 summarizes the reduction in greenhouse gas emissions from electric power generation if the U.S. combined-cycle plants are operated as base-load units. Greenhouse gas emissions would decline by more than 20 percent.

Smart regulation of natural gas pricing would benefit natural gas producers and assure major progress on reducing greenhouse gas emissions from electric power generation. Natural gas producers would benefit from a regulated pricing regime that sets a floor price that assures a profit and protects the producer from bust cycles. This pricing regime would also set a price ceiling that prevents critical progress on climate change from being subordinated to speculative natural gas bubbles that drive electric utilities back to heavy reliance on coal generation for cost reasons.

This natural gas regulatory structure has been applied in the past in the United States, with mixed results. In the 1960s, the fixed price of natural gas set by the Federal Power Commission (FPC) was too low to encourage exploration for natural gas.13 This created a situation where the price was low but the supply was decreasing at a time of rising demand. In the 1970s, the FPC fixed the price of "old gas" and "new gas" ostensibly at levels that provided adequate return on investment for existing natural gas fields and encouraged new natural gas production. Natural gas price controls were effectively removed in the 1980s. The lessons learned from earlier periods of price regulation in U.S. natural gas markets would need to be incorporated in new price regulation to assure an adequate supply of natural gas priced incrementally above the cost of production.

A HUGE OPPORTUNITY IS AVAILABLE

Displacement of conventional gas-fired peaking gas turbines by PV generation would contribute to cost-competitive natural gas prices over the long term. The beneficial ripple effect of this downward pressure on natural gas prices would be the displacement of coal plants by natural gas–fired combined-cycle plants for base-load generation with little or no cost impact on electric power consumers. A unique set of circumstances—abundant natural gas, static demand, availability of cost-competitive PV generation, and 200,000 megawatts of under-used combined-cycle capacity—presents a framework for a national energy strategy that would rapidly reduce greenhouse gas emissions from electric power generation at minimal additional cost to U.S. electricity consumers.

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business as usual* cc plants at high-capacity factor**
fuel % of electricity cO2 MMtpy fuel % of electricity cO2 MMtpy
coal 49 2,200 coal 29 1,300
natural gas 21 360 natural gas 41 700
fuel oil 2 40 fuel oil 2 40
nuclear 19 0 nuclear 19 0
hydro 6 0 hydro 6 0
renewable 3 0 renewable 3 0
2,600 2,040
*Edison Electric Institute, 2007 Industry Data (online)—total electricity generated by coal is 2,020 million MWh, total

by turbines is 893 million MWh.
Average U.S. demand is approximately 475,000 MW. Assume 200,000 MW of (combined-cycle) capacity at 45 percent annual

capacity factor and 170,000 MW of simple-cycle turbine capacity at 5 percent annual capacity factor.
**Edison Electric Institute, 2007 Industry Data (online) source of combined-cycle (CC) and combustion turbine (CT)

totals: EIA 2000 inventories of utility and nonutility generation assets, 2008 Q1 Combined Cycle Journal article on CC and CT additions, 1998–2008.

Assume existing 200,000 MW of high-efficiency combined-cycle plants ramped up to base-load operation, from 45 percent to 90 percent, and the composite capacity factor for
350,000 MW of coal plant capacity is ramped down, from 66 percent to 30 percent.
exhibit 4. CO2 Emissions Reduction From Electric Power Generation if

Combined-Cycle Plants Operate at
High-Capacity Factors business as usual* cc plants at high-capacity factor**
fuel % of electricity cO_2 MMtpy fuel % of electricity cO_2 MMtpy
coal 49 2,200 coal 29 1,300
natural gas 21 360 natural gas 41 700
fuel oil 2 40 fuel oil 2 40
nuclear 19 0 nuclear 19 0
hydro 6 0 hydro 6 0
renewable 3 0 renewable 3 0
2,600 2,040
*Edison Electric Institute, 2007 Industry Data (online)—total electricity generated by coal is 2,020 million MWh, total

by turbines is 893 million MWh.
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composite capacity factor for
350,000 MW of coal plant capacity is ramped down, from 66 percent to 30 percent.
exhibit 4. CO_2 Emissions Reduction From Electric Power Generation if

Combined-Cycle Plants Operate at High-Capacity Factors

NOTES

1. Also, as in this instance, used as a shortened expression for "photovoltaic-generated electricity."
2. California Energy Commission (CEC). (2007, December). Comparative costs of California Central Station electricity generation technologies—Final staff report, CEC-200 -2007-011-SF, December 2007, Table 3: Levelized Cost Components—Merchant Plants, p. 10 and Table 10: Fuel Prices, p. 23. A capacity factor of 5 percent is assumed by the CEC for a conventional 50-megawatt peaking gas turbine. Of $647 a megawatt-hour of levelized COE for a peaking gas turbine, $536 a megawatt-hour is associated with fixed capital and operations and maintenance (O&M) costs and $80 a megawatt-hour is associated with fuel cost (in 2007 dollars). A natural gas cost of $6.87 a million Btu's is assumed by the CEC for 2009, and $5.69 a million Btu's is assumed for 2010.
Note that the assumed 2009 natural gas cost is nearly double the July 2009 natural gas spot price. However, fuel cost is a relatively minor component of the overall levelized COE calculated by the CEC for a conventional peaking gas turbine. As a result, the cost-competitiveness of distributed PV with a peaking gas turbine is not substantially affected by a significant reduction in the assumed cost of natural gas—and regardless, PV costs are dropping, too.
3. Assumes composite gas turbine heat rate, including both combined-cycle base-load units and simple-cycle peaking units, of 8,000 Btu's a kWh.
4. Navigant Consulting, PV grid-connected market potential under a cost breakthrough scenario, PowerPoint report prepared for Energy Foundation, September 2004, 2010

Table—Technical market for PV in MWp in 2010 by state and segment, p. 83.
5. Powers, B. (2007, October). San Diego Smart Energy 2020. Prepared by E-Tech International, Santa Fe, NM; pp. 30–31.
6. Smith, J. C., & Parsons, B. (2007, November/December). What does 20% look like? IEEE Power and Energy Magazine, p. 24: Figure 1—States with RPS Requirements.
7. Energy Information Administration. (2009). 2009 annual energy outlook. Washington, DC: Author; Figure 55—Electricity Generation by Fuel in Three Cases, 2007 and 2,030 billion kilowatt-hours. Here, 2007 U.S. electricity generation = 4,137 billion kilowatt-hours (or 4.137 million gigawatts).
8. Energy Information Administration. (2009, March 2). 2008 crude oil imports from Persian Gulf highlights. Retrieved August 3, 2009, from http://www.eia.doe.gov/pub/oil_gas/petroleum/data_publications/company_level_imports/current/summary2008.html. Total Persian Gulf imports in 2008 were 844.9 million barrels.
9. Schreiber, D. (2008, December 1–2). PV thin film markets, manufacturers, margins. PowerPoint presentation, 1st Thin-Film Summit, San Francisco, p. 13.
10. Energy Information Administration. (2009, May). Short-term energy outlook supplement: The implications of lower natural gas prices for the electric generation mix in the southeast, pp. 3, 11. Retrieved August 3, 2009, from http://www.eia.doe.gov/emeu/steo/pub/special/pdf/2009_sp_02.pdf.
11. Ibid, p. 12. A delivered natural gas price decline from $4.75 a million Btu’s to $3.50 a million Btu’s results in an increase in combined-cycle plant fuel consumption from 0.7 billion cubic feet a day to 7.2 billion cubic feet a day. Assuming a median combined-cycle plant heat rate of 7,500 Btu’s a kilowatt-hour (high heating value), 7.2 billion cubic feet a day of natural gas consumption represents 40,000 megawatts of continuous combined-cycle generation and an 80 percent capacity factor for the 50,000-megawatt inventory of

combined-cycle plants in the South Atlantic region alone.
12. Shuster, E. (National Energy Technology Laboratory). (2009, June 23). Tracking new coal-fired power plants. PowerPoint presentation, p. 5.
13. Davis, D. H. (1993). Energy politics (4th ed.). Belmont, CA: Wadsworth; pp. 153–162.

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