An initial critique of Dr. Charles R. Frank, Jr.'s working paper "The Net Benefits of Low and No-Carbon Electricity Technologies," summarized in *The Economist* as "Free exchange: Sun, wind and drain"

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It is sometimes instructive when capable economists analyze the electricity system—but dangerous when misleading results distort public policy and private investment. Dr. Charles R. Frank, Jr.'s May 2014 Brookings working paper "The Net Benefits of Low and No-Carbon Electricity Technologies" and its blog entered that category when the normally careful *Economist* devoted a page to it on 26 July 2014 (24 July online), bringing it to far wider attention without noting its serious analytic flaws. Two posted rebuttals are useful but rather narrowly framed—one by the American Wind Energy Association's Michael Goggin, the other by utility experts Ron Binz and Dan Mullen—plus a podcast (at 3:00–19:00) by Stephen Lacey, Jigar Shah, and Katherine Hamilton. Perhaps our collective initial impressions will encourage more analysts to join a richer and more illuminating conversation. Here's my key conclusion:

Using Dr. Frank's methodology but adopting empirical data on key points reverses his findings: the priority becomes hydro, gas combined-cycle, wind, solar, and last of all nuclear.[1]

The issue Dr. Frank raises is real: electrical resources should be chosen based on their time-varying benefits as well as their long-run levelized costs. But his methodology could not validly address that issue even if he'd used correct data, and as I'll detail next, many of his basic data are wrong. So…good question, wrong answer.

Dr. Frank assumes wind and solar power are 1/3 to 1/2 less productive than they are

Dr. Frank assumes these U.S. average capacity factors—the fraction of a plant's theoretical full-load output that it actually sends out during a year:

Wind 25.5%
Solar photovoltaics (PVs) 15.5%
Gas combined-cycle 92.0%

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[1] His results are extremely sensitive to assumptions not transparently tested, so my colleague Titiaan Palazzi (whose research support I gratefully acknowledge) recreated Dr. Frank's spreadsheets, reproducing his coal-displacement-case results and then correcting a spreadsheet error in his Table 2A's non-wind offpeak hours per year. Adopting key empirical data documented below—EIA's national-average 2008–13 wind and PV average capacity factors without "adjustment" (but with a 45% *onpeak* PV capacity factor conservatively estimated from two state studies), DOE's 2012 national-average wind and PV costs, EIA's 2008–13 gas-CC capacity factor, NEI's 2012 nuclear opex, 2004–13 global-average nuclear construction time (9.4 y), and 1.5% methane leakage—reverses his results. The priority at $50/TCO_2$ becomes hydro, wind, gas CC, nuclear, solar. Solar capex at Lazard or approximate actual 2013 market levels (~$2,000/kW) then puts solar ahead of gas and nuclear. We changed no other methodology or data from Dr. Frank's paper. Counting gas's price volatility would relegate gas combined-cycle from second place to a low priority.

His cited source, the U.S. Energy Information Administration's (EIA's) *Electric Power Annual 2012*, omits the Table 4.8.B listed in its Table of Contents as showing capacity factors calculated from each renewable unit's online and retirement dates. Its Appendix's definition of "Average Capacity Factors" explains those correct data "will differ from a simple calculation using annual generation and capacity totals from the…tables"—apparently what Dr. Frank used—because annual capacity is measured on 31 December, but new units (wind and solar grow quickly) may have been installed too late to contribute much to annual output.

Worse, he averages 2002–12 data, and weights them by year, not by capacity or output. More and better equipment produced about 12x more windpower and 100x more solar power in 2012 than 2002, so this methodology submerges modern practices in obsolete ones. Wind turbines, for example, produce power proportional to the cube of windspeed, but turbines operating in the late 1990s were nearly 30 meters lower, three-fifths smaller, and far less efficient than those added in 2012. Dr. Frank's claimed PV maximum capacity factor of 19% (based on one data point, from an apparently unpublished 2008 working paper describing a single small Arizona array monitored for two years) compares with 28–30% for the cumulative output of 17 modern Western PV projects—31% for the best, lately risen to nearly 35%.

It would have been simpler and far more accurate to use modern data. The missing table is in the latest (30 July 2014) online EIA data, which for 2008–13 show 31.0% average wind capacity factor (and for the first five months of 2014, 38.2%); for PVs, a 2008–13 average of 20.4% (and for the first five months of 2014, 22.5%). Thus by not using the readily available modern national data sets, Dr. Frank systematically understates the productivity of the two main variable renewables by more than one-fifth—or for 2014 so far, when the most recent equipment is a larger share of the installed fleet, by more than one-third.

Of course, national-average projects underperform the most productive and competitive wind and solar capacity built in the windiest and sunniest regions. The latest U.S. Department of Energy (DOE) data show typical midwestern windbelt capacity factors from 35% to over 45%, and over 50% for some 2011–12 projects. (Dr. Frank's own reference—an undated ~2010 lay factsheet—says windpower capacity factors are "typical[ly] 20–40%," but he assumes 25.5%.) Similarly, DOE's latest national data show that recently installed utility-scale PVs have cumulative capacity factors around 15–27% without tracking (i.e., fixed-tilt) or about 20–30+% (now almost 35%) with tracking, with the higher values in the sunnier locations. Thus compared with the relatively favorable areas in which smart developers mainly build—areas that could accommodate far more capacity than the nation needs—Dr. Frank's renewable output assumptions are at the lower bound of a twofold empirical range, understating actual output by up to half.

For gas combined-cycle plants, he makes a twofold error in the opposite direction. Rather than adopting the actual average capacity factor shown by DOE data—44.2% for 2008–13, 46.5% in 2013, or 41.7% for the first five months of 2014—Dr. Frank assumes 92% from a Siemens press release, representing what that vendor says its technology could do if run whenever available. In the United States, despite relatively cheap gas, it is seldom so run—

and far less in Germany with its costlier gas and deeper renewable competition—because that would be uneconomic, and would be even more so at Dr. Frank's higher future gas prices. So by reducing renewable output by as much as half, then doubling gas-fired output to its theoretical maximum, he overstates by up to fourfold the productivity of gas-combined-cycle relative to wind or solar plants.

He also may exaggerate the amount of coal-fired electricity that will be left to save by policy intervention. The average capacity factor of U.S. coal plants fell from 73.4% in 2008 to below 60% in 2012–14. In 2012, that reduction was caused nearly twice as much by efficiency as by fracked natural gas. But as efficiency continues to erode electricity demand, and as ever-cheaper renewables continue to undercut coal's operating costs, coal-plant capacity factors will continue to fall. Already, the average coal plant, rather than running nearly all the time in the semi-mythical mode Dr. Frank calls "baseload" (see below), achieves a capacity factor modestly above those of the best windfarms.

Dr. Frank assumes wind and solar power cost about twice as much to build as they do

Based on an EIA forecast published in 2013, performed in 2012, using still older data—well-known among technology experts to be a poor basis for assessing plummeting renewable costs—Dr. Frank assumes overnight capital costs of $2,213/kW for a new wind plant and $3,873/kW for a new PV plant. Adding cost of capital during construction yields installed costs (which I assume are actually installed *prices*) of $2,351/kW for wind and $4,115 for PV. Yet these figures are badly outdated.

For U.S. windpower, the actual capacity-weighted average 2012-$ installed price in 2012 was $1,940/kW and falling, just $1,760/kW in the windy interior region, and for the lowest-cost projects, only about $1,400/kW—two-fifths below Dr. Frank's $2,351/kW assumption. Dramatic further drops were reported in 2013–14—apparently the average fell by ~$300/kW in 2013, with the official data due for release shortly in Lawrence Berkeley National Laboratory's annual digest. Dr. Frank further disadvantages windpower by assuming each project lasts only 20 years rather than the modern industry-standard 25, thus increasing its annual capital charge by one-fourth. Some operators even say their expert monitoring and maintenance should enable their turbines to keep running far beyond 25 years.

For U.S. utility-scale PV projects added in 2012, the actual average installed price was about $3,300/kW for crystalline or $3,200/kW for thin-film fixed-tilt systems. Nearly all projects >20 MW cost well below Dr. Frank's $4,115/kW assumption (that is, his supposed average was actually near the upper bound), many were priced below $3,000/kW, and the cheapest projects had installed prices around $2,300/kW, or about $2,500/kW at utility scale. The latest official data for the first half of 2013 suggest even faster drops in system prices than in 2012, largely because—unexpectedly for Dr. Frank (cf. p. 12 of his paper)—balance-of-system (non-module) prices are falling rapidly too as U.S. installers catch up with the streamlined techniques that enabled German residential PV installers to achieve half the U.S. installed price even though they all buy the same equipment. That's why, according to early-2014 public statements by CEO Lyndon Rive, SolarCity's installed residential system costs fell 30% in 2013 even though his module prices rose 3%. Consistent with these trends, Lazard's 2013 analysis uses a utility-scale PV capital cost of $2,000/kW tracking or $1,750/kW fixed-tilt—the latter falling to $1,500/kW in 2015.

The "joker in the pack," says Bloomberg New Energy Finance, is that unsubsidized rooftop PVs should beat retail power prices in much of the world by 2025, including large parts of the U.S. (as they do today in at least 20 states where installers finance them with no money down), so they're likely to get $1.3 trillion of investment and add 1,000 GW of capacity worldwide in the next 11 years. Two of the July 2014 BNEF forecast's three big wildcards are even *more* efficiency and even *more* distributed solar.

Dr. Frank understates empirical nuclear costs by twofold, operating costs by fivefold

Dr. Frank's assumptions about the costs of U.S. nuclear plants look dubious too. He assumes below-market nuclear capital costs and half-global-average construction time (5 *vs.* 9.4 y), and omits new-build U.S. nuclear plants' ~100% construction subsidies, as well as nearly all their operating subsidies (which have a slightly higher levelized value than those that windpower used to get), but I won't take time here to review these. The *Economist* article, too, refers to renewables' temporary subsidies but not to the generally larger and permanent subsidies to fossil-fueled and nuclear systems. Most serious students of energy subsidies think removing them all would increase adoption of renewables.

Dr. Frank seems in Table 4A to say that a new nuclear plant will have an operating cost of $9.22/MWh. According to the Nuclear Energy Institute, the actual 2012 cost (2012 $) was $44.17, or 4.8-fold more, comprising $7.35 for fuel and $23.86 for routine operation and maintenance (of which Dr. Frank shows only a $2.14 variable part—his Table 5 shows fixed O&M costs for gas and coal plants but not for nuclear). Apparently Dr. Frank omitted both nuclear fixed O&M costs and NEI's reported $12.96/MWh of net capital additions. Those major repairs and modifications are capitalized rather than expensed, but (like fixed O&M) needn't be incurred if the plant doesn't run, so they are, as NEI agrees, properly classified as operating costs, unrelated to initial capital investment. Dr. Frank is also unlikely to find anyone willing to guarantee to decommission a typical power reactor for $300–400 million or dispose of its spent fuel for $100 million; realistic, modern, independent estimates could move those decimal points one place to the right. His apparent total new-nuclear busbar electricity price of $88/MWh is about half the subsidized ~$155/MWh U.K. market price.

Inexorably rising nuclear operating costs have already made many U.S. reactors, even some well-running ones, uncompetitive with falling wholesale power prices (driven down by windpower as well as cheaper natural gas), causing their owners to start shutting them down. Dr. Frank's statement, on p. 18, that "Nuclear plants have always had energy costs much lower than those of fossil-fuel plants. Therefore a nuclear plant is…always likely to be dispatched" is no longer true in much of the United States (or Germany or Sweden). And when existing nuclear plants whose capital cost was sunk long ago often cannot compete just on *operating* cost, analyzing new ones with enormous new *capital* costs too, let alone finding they are the most cost-effective new carbon-saving choice, seems the height of fantasy.

Dr. Frank's natural-gas analysis omits price volatility and methane leakage

Dr. Frank compares his assumed gas and other fuel prices, via their resulting electricity production costs, with renewables *without* risk-adjusting for fair comparison. Yet basic financial economics requires this because fuel prices are volatile, whereas renewable (and efficiency) prices are essentially fixed once the equipment is installed. Not counting the market value of, say, gas-price volatility—discoverable from the straddle in the options market—represents an error currently worth about $1–3 per million BTU; the upper end of this range approaches today's U.S. wholesale gas price. Dr. Frank's error is analogous to buying a bond portfolio of all junks and no Treasuries by looking at only at the price or yield but not also at the risk—not a mistake one would make for long, nor expect from a professor of economics. Indeed, one of the most important Wall Street financiers in the power sector has formed a team specifically to market renewables' lucrative gas-price hedge value, which Dr. Frank implicitly values at zero.

Further, despite extensive recent discussion of how even small methane leaks from the natural-gas system may offset or reverse gas's climate advantage over coal, Dr. Frank and his cited source seem to assume zero methane leakage—well below the unknown but apparently significant actual level. His conclusions should be very sensitive to actual leakage rates, but methane leaks aren't mentioned.

Dr. Frank understates onpeak *solar capacity factor, then reduces it asymmetrically*

Dr. Frank adds three novel errors when comparing renewables' value with that of gas- or coal-fired electricity. First, his Table 2A assumes, with an unstated basis, that PVs have a 20% capacity factor *during the 800 highest-demand (peak) load hours in the year*—not far above his assumed 15.1% offpeak or 15.5% annual capacity factor. Yet the authors of his citation for 19% maximum PV capacity factor earlier reported 26.8% *summer* (let alone summer onpeak-hours) capacity factor for another small Arizona array—*twice* its winter value. Most U.S. peak load hours occur in early to midafternoon when solar output is at its maximum—especially if the modules point southwest or west to produce more power when it's most valuable, as some smart operators routinely do. For example, even in relatively cloudy New York State, low-penetration capacity credits representing measured peak-hours output from southwest-facing PVs are 70–90%, though *annual* capacity factors are in the upper teens. Utilities' summer 2012 New England measurements, too, found PVs' contribution to system peak to average 40% of rating. It thus appears that Dr. Frank has understated PVs' onpeak capacity factor—or more precisely, Effective Load Carrying Capability—by severalfold, slashing their economic value. This less affects carbon savings, mostly from displacing coal; but greater use of renewables will indeed displace coal and combined-cycle gas too, not just simple-cycle peakers as he assumes, via merit-order shifts.

One of solar power's best-known system advantages is that its output is highly coincident with peak load, as Dr. Frank admits when he correctly states that levelized-cost comparisons undervalue solar power compared to windpower: for exactly that reason, PV does beat wind today in some markets. The sunnier the day, the higher both the solar output and the air-conditioning load that drives most of the peak system load. (The two are not entirely coincident: California south-facing PV output tends to peak in early afternoon and demand in late afternoon, but there's significant and valuable overlap.) But he greatly understates this solar advantage. Whether windpower, as he also assumes on equally scant evidence, produces less output onpeak than offpeak depends strongly on local topography, wind patterns, and loadshapes; his inference of mainly nighttime output is an improper generalization.

His capacity-factor "adjustments" reflect misunderstandings of how grid reliability works

Second, not content with using far below actual capacity factors for variable renewables, Dr. Frank "adjusts" them even further down—to 20.4% for windpower and 12.0% for PVs—by applying a strange methodology meant to reflect their lower reliability, "not because they are mechanically more prone to forced outages [actually they are far *less* prone], but because the availability of wind [or] sun…is highly variable" and, he assumes, can be restored only by prohibitively costly bulk electrical storage. He therefore estimates "a 99 percent confidence level capacity factor (the adjusted capacity factor) for the new plant and for the plant that it replaces," based (per his endnote 4, though details are unclear) on a decade of *annual* EIA data. He would have preferred to use shorter-term—hourly or less—renewable variance data but, oddly, could not find them, so he's treated the annual data as a meaningful proxy for the "hourly or less" fluctuations that he agrees most matter to grid operators. This is utterly foreign to how those operators actually analyze reliability.

Nobody familiar with grid integration of variable renewables would dream of using Dr. Frank's crude methodology. Proper grid simulations use other, and very sophisticated, probabilistic techniques to assess the variability and uncertainty of renewable and other resources on the full range of timescales. Dr. Frank's inferences from annual-average data show no familiarity with the literature's conventional and correct distinction between three main timescales (regulation from minute to minute, load-following over minutes to hours, and scheduling in the day-ahead unit-commitment decisions—not to mention long-term resource acquisitions). This suggests that he is far outrunning his disciplinary headlights. He doesn't even seem to understand that the term "baseload" conventionally has an *economic* definition in the electricity business: utility resource buyers use it to mean the resource of lowest total levelized cost; utility system operators, the resource of lowest short-run marginal cost. These orthodox economic definitions are now often best fitted by efficiency and renewables—not, as Dr. Frank assumes, by big fossil-fueled or nuclear power plants—even for "baseload" in the load analyst's sense (loads whose aggregate appears steady and lies below the shoulder of the load-duration curve).

His capacity-factor "adjustments" are inappropriately small for large thermal stations

Third, Dr. Frank's methodology is not symmetrically applied. He "adjusts" actual average capacity factors to a level 99% likely to be met every year for a decade—decreasing windpower output by 22%, PV by 21%, and hydro by 16%. Yet he arbitrarily decreases nuclear and gas combined-cycle outputs by only two percentage points or 2%. This seems implausible. A Danish grid operator, for example, remarked that he can have higher confidence (~98%) that windpower will deliver its forecast output an hour later than that a simple-cycle gas turbine will actually start and be producing its rated output an hour after he presses the START button (~96%). This is partly because fueled plants are more complex, with more to go wrong, and partly because their failures are lumpier (more capacity fails at once) than a diversified portfolio of small units. In fairness, Dr. Frank's footnote 6 says "more work needs to be done in estimating 99 percent confidence level capacity factors for nuclear and fossil fuel plants," and admits his estimates "are not backed up by hard data," but it's unclear why he "believes that better data would increase [those plants'] adjusted capacity factors"—especially for his preferred option, nuclear power, because nuclear plants are unusually prone to very long forced outages.

Through 2006, 41 U.S. power reactors suffered 51 outages lasting at least a year (ten of them twice), each equivalent to more than nine back-to-back refueling intervals of 38 days. Those outages affected nearly a third of the 130 units licensed and cost nearly $100 billion in today's dollars. They also added up to nearly 135 reactor-years or over 4% of cumulative experience, flunking Dr. Frank's 99% confidence level. Such a prolonged loss of a billion watts of capacity, often without warning, is far harder to manage than the rather brief, predictable and partly offsetting fluctuations of wind and PV power. Incidentally, nuclear SCRAMs (rapid shutdowns for safety) automatically triggered by grid failures can also *cause* prolonged outages, as in the August 2003 northeast blackout: nine U.S. units plunged from 100% to 0% output, then took 12 days to regain full power, and in the first few days produced almost nothing, largely due to fission products' effects on neutronics. This "anti-peaker" attribute of being assuredly unavailable when most needed has no parallel in diversified portfolios of modern renewables.

Why analyze capacity value when almost nobody needs new capacity?

Dr. Frank's study is all about what kind of new capacity to buy for optimal climate protection, and how much carbon and money it will cost or save. But in the United States today, there's almost no market for new generating capacity: most utilities have far more than they need, and electricity demand has been shrinking since 2007 with no relief in sight.

If U.S. power markets needed more capacity to meet system peak loads, their least-cost and least-carbon investments would be on the demand side: electric efficiency (which could optimally save three-fourths of U.S. electricity by 2050 at an average technical cost around $6/MWh, and in which utilities invest $7 billion a year at average costs ~$20–30/MWh) and demand response (unobtrusively flexible demand enabled by proper pricing, modern telecommunications, and smart grids). Dr. Frank ignores the demand side entirely; like many economists, he may think of demand-side resources not as competitive resources but as abstract shifts of or along a demand curve. Yet power auctions in three-fifths of U.S. states now compete demand-side resources directly against new supply. Demand-side resources generally win because they cost less—and they often save especially onpeak.

The next winner is typically modern renewables, which—first at a household scale, where they compete against retail not wholesale prices, then in bulk supply—often already beat *new* and increasingly beat *existing* thermal power stations: installers in ~20 states beat household utility bills using rooftop PV systems financed with no down payment. Customers may want to buy efficiency or renewables cheaper than utility electricity even though utilities have ample capacity to meet system peak loads. Many customers are doing so. As batteries too get cheaper (by 43% from 2010 to early 2014), some customers are dropping off the grid altogether. Such competitive "utility-in-a-box" bypass of the grid will become generally competitive well within the life of existing U.S. utility assets, leaving the old central-station business models no place to hide.

Low demand growth implies less coal- and gas-fired generation. However, the United States' utilities already have almost no need for new capacity of any kind. Rather, as a front-page *Wall Street Journal* article just noted, the industry's challenge is stagnating or falling demand, so current prices can't cover existing plants' rising costs. Of the 13 regions assessing summer-2014 reliability, none is short of capacity; only one, spanning the midwest from the Dakotas and Wisconsin to Louisiana, is *at* its reserve-margin target of 15%; another (most of Texas) is one percentage point above its 14% target; and the rest are oversupplied by a generous and costly 7–16 percentage points. The two regions relatively close to target are especially rich in competitive renewable potential.

For example, recent long-term Power Purchase Agreements for PVs in Texas are priced below $50/MWh, and in the midwestern windbelt, wind PPAs are priced as low as $20/MWh —*vs.* Dr. Frank's apparently calculated $261 and $124/MWh. That is, he claims typical solar and windpower must cost over five and six times, respectively, what experienced developers sold them for last year in favorable regions. (This discrepancy far exceeds the temporary Federal subsidies of 30% for PVs and $18–28/MWh for wind.) But wind and PV's actual market prices in many areas now beat new combined-cycle gas power and even just the *operating* cost of some *old* coal and nuclear plants. *New* gas, coal, and nuclear plants are far out of the money. Analyzing the environmental value of not building more of them is superfluous when they have no business case based just on their private internal cost.

In confirmation, AWEA's Michael Goggin notes that in power pools like PJM where capacity markets exist and let demand-side resources bid, new capacity's market value is far too small to justify building a new power plant—exactly as one would expect when overcapacity shows there's no need for one. By counting avoidable capacity value nonetheless, not just the fixed O&M cost of running existing capacity, Dr. Frank overstates new capacity's economic value by about 7–10-fold, creating most of the spurious value he ascribes to gas-fired and nuclear power plants.

Integrating variable renewables into the grid doesn't work as Dr. Frank assumes it does

Dr. Frank agrees on p. 13 that the "balancing costs" of integrating variable renewables into the grid are quite small, typically around $3/MWh, and that efficiency losses from running some fossil-fueled plants below their optimal loadpoints are also modest (they're typically a few percent). Essentially all competent analyses of grid integration costs, whether in Europe, the U.S., or elsewhere, show they're just a few percent of total power costs. (There are also poorly done analyses making one or more of the methodological errors catalogued in important NREL papers (see here).) Dr. Frank could rightly have concluded that grid operators can and do manage the variability and uncertainty of wind and PV power at very low cost, so there's no more to analyze. But instead of simply adding empirical balancing costs—calculated or discovered in power markets—he's attempted a new mode of analysis—"adjusting" already halved capacity factors of wind and PVs to still lower levels (see above). His underlying assumption, contrary to observed investment and operating behavior, is that without uneconomic bulk storage, variable renewables cannot *reliably* contribute nearly as much to supply as their capacity factors imply. The most widespread fallacy in today's electricity discussions is this notion that reliable grids with variable renewables require bulk storage, or backup by existing fossil-fueled plants, or both. In fact, those are the costliest ways to provide grid flexibility, so they would be bought last, not first (or for other reasons). Generally lower on the supply curve of grid-flexibility resources are six cheaper options, whose exact sequence may vary:

- End-use efficiency, which not only saves electrical energy—its central purpose—but also typically makes loads less peaky
- Demand response—enabling customers or their devices to use electricity at times when it's more abundant and hence cheaper
- Backing up variable renewables with other variable renewables—of other kinds or in other places—as part of a diversified portfolio (e.g., in each of three midwestern balancing areas from Texas to the Canadian border, the same firm demand can be met with less than half as much wind capacity just by combining anticorrelated sites; adding solar diversity works even better)
- Backing up variable renewables with a diversified portfolio of *dispatchable* renewables (nearly all renewables other than wind and PVs are usable whenever needed: geothermal, old big hydro subject to some fish-protection and other regulatory constraints, small hydro, solar-thermal-electric with heat storage, municipal waste combustion, biomass and biogas combustion, and to varying degrees most kinds of wave, tidal, and other marine energy)
- Distributed storage of heat or coolth that electricity would otherwise provide, such as ice- or chilled-water-storage air conditioning (as Hal Harvey points out, the U.S. already has a hundred million large thermal storage devices called "buildings" that can be preheated or precooled with resources like night windpower)
- Distributed storage in intelligently interconnected electric vehicles that are bought primarily for mobility but sit idle about 96% of the time, and whose smart interconnection with the grid offers stunning new business models

Combining these resources with accurately forecasted wind and PV output (both can generally be forecasted nowadays as least as accurately as electricity demand) can usually make mostly or wholly renewable electric supply meet both steady and varying loads with current reliability or better. This is especially true if generators become more distributed, since ~98–99% of power failures originate *in* the grid, so bypassing the grid by siting generators at or near customers can avoid most power failures at their source.

Denmark is shifting its grid architecture to a "cellular" web of microgrids that normally interconnect but can stand alone at need, disconnecting fractally and reconnecting seamlessly. Denmark, roughly half renewably powered, and Germany, over one-fourth renewably powered, have the most reliable electricity in Europe—about ten times better than the U.S. Netted islandable microgrids are also the Pentagon's strategy for powering military bases, and they're the way my own house works, serving all key loads with or without the grid.

This approach suffices in many simulations including the Renewable Energy Futures Study, a collaboration of 35 national laboratories, firms, universities, and NGOs. Using NREL's very sophisticated ReEDS model, REFS robustly found centralized 80%-renewable supply "in combination with a portfolio of flexible electric system supply- and demand-side options is more than adequate to supply 80% of total U.S. electricity generation in 2050 while meeting demand on an hourly basis in every region of the United States," using bulk storage (including existing pumped hydro) equivalent to only 11% of renewable capacity. RMI's cost-neutral but risk-reducing *Transform* scenario in *Reinventing Fire*, also using the ReEDS model, found that half-distributed renewables meeting 80% of 2050 loads, with closer attention to profitable end-use efficiency, could do the same on an hourly basis with 188 GW of storage or 13% of renewable capacity, including 69 GW of ice storage and 44 GW of batteries (in cars or not); bulk electrical storage totaled only 5% including pumped hydro.

Such carefully simulated findings are being borne out in practice, directly refuting Dr. Frank's claims. In 2013, four European nations—not hydro-rich Norway, Sweden, or Iceland—got about half their electricity consumption from renewables (Spain 45%, Scotland 46%, Denmark ≥47%, Portugal 58%) with excellent reliability and no additions of bulk storage. Rather, they operated their existing assets, as my colleague Clay Stranger puts it, much as a conductor, using score and skill, leads a symphony orchestra: not every instrument plays all the time, but the ensemble continuously produces beautiful music.

Dr. Frank's analysis reflects the common error of supposing that grid integration is a cost only of variable renewables, not of *all* electrical resources—notably of big thermal power stations. As the NREL review says in summary:

> Other generation technologies [than wind and PVs] impose integration costs which are not allocated to those technologies. Large generators impose contingency reserve requirements, block schedules increase regulation requirements, gas scheduling restrictions impose system costs, nuclear plants increase cycling of other baseload generation, and hydro generators create minimum load reliability problems. None of these costs are allocated to the generators that impose them on the power system. Any policy that assigns integration costs to wind and solar needs to be thought through very carefully to assure that it is not discriminatory.

Diverse U.S. utilities' analyses of grid integration costs, summarized every year in LBNL's wind market report, show that the balancing reserve required for windpower is usually *less* than the canonical reserve margin for a system dependent on big thermal units (~15–20%, some of it spinning reserve) to cover the lumpy failure contingency of the big thermal units. LBNL summarizes at p 64: "With one exception [which appears methodologically flawed], wind integration costs...are below $12/MWh—and often below $5/MWh—for wind power capacity penetrations up to and even exceeding 40% of the peak load...." In other words, evidence is emerging, in both theory and practice, that grid integration costs may be *higher* for a system largely dependent on big thermal generators than for one largely dependent on variable renewables. Conversely, high-renewables futures may need *less* backup and storage than utilities *already bought* to manage the intermittence of their big thermal power stations, which fail less gracefully than a sensible renewable portfolio.

The historical but unconvincing difference is that grid integration costs for big thermal units are typically socialized as inevitable "system costs," while those for variable renewables are considered extra and exceptional, and may be charged to their developers. This asymmetry is both common and wrong. But it is starting to be noticed, especially through Fraunhofer's studies showing that most costs and difficulties ascribed to integrating German variable renewables are due to the inflexibility of uncompetitive big thermal units whose owners insist on running them. A competitive grid unburdened by “must-run” resources becomes, naturally, far more flexible.

To be sure, this works best with larger balancing areas whose markets clear more often, with transparent power flows and pricing, and with grid operators who (like many in Europe) have gained experience and comfort with operating their assets differently. But it follows the correct economic principle that costs should be allocated to the technologies or operations that cause them; otherwise small generators cross-subsidize large ones and flexible ones cross-subsidize inflexible ones. Following Dr. Frank’s erroneous prescription would intensify those cross-subsidies.

Economics is a useful climate-protection perspective if properly applied

Dr. Frank, like Prof. Paul Joskow whose paper underlies his, is correct that levelized costs do not capture resources’ value at different times. However, Dr. Frank’s odd methodology, even if he used correct data, would not be necessary or appropriate for capturing that time-varying value. Conventional and accepted ways to simulate power systems with and without variable renewables, examining all their interactive effects on costs and benefits, capture it fully without introducing new errors.

I also agree with Dr. Frank that a sensible U.S. carbon price would be highly desirable—though I think it’s not essential (*Reinventing Fire* found a $5-trillion net-present-value private-internal-cost surplus without it) nor sufficient (because proper pricing without busting barriers does little). In the long run, too, carbon pricing is not as important as many suppose, because the overhang of unbought efficiency is such a large fraction of demand that an efficient carbon market will ultimately clear at low prices. (This may be invisible to Dr. Frank because he omits all demand-side resources.) However, we certainly have common ground that carbon pricing is economically correct, is sound policy, and should be adopted without delay: the right number is not zero. Pricing carbon will equally advantage all resources whose operation emits no carbon—efficiency, renewables, nuclear power—and will partially advantage low-carbon combustion resources, notably gas-fired cogeneration and combined-cycle gas-fired plants with very low end-to-end gas-system leakage.

Economics can be a useful lens through which to view grid operation. Prof. Joskow is one of the distinguished economists who have contributed to our understanding of least-cost grid operation and the public policy that drives it. But the way Prof. Frank applies his carbon-pricing lens does not expand but constrains our understanding, because it counts none of the other important external or hidden costs and benefits that should be counted. Neither the more than 200 non-climate external benefits of distributed and renewable resources, nor the immensely valuable external benefits of end-use efficiency, nor the importance of desubsidizing fossil fuels and the whole energy sector in both the U.S. and the rest of the world, nor the climate and security benefits of efficiency and renewables support Dr. Frank's findings.

Let me also add here a plea for clearer language. Dr. Frank refers to wind and PVs as "intermittent." I suggest we reserve "intermittence" for unforecastable forced outages (in any technology), and call wind and PV, whose fluctuations are highly predictable, "variable" resources. That small but useful step could reduce the muddled thinking and miscommunication that pervaded this field long before Dr. Frank's paper.

Conclusions

It *is* important to compare different ways to displace coal-fired power plants and their carbon emissions in value as well as in cost. Standard methods used in competent grid-integration analyses already do this correctly. Dr. Frank's attempt, using nonstandard methods that such experts are unlikely to adopt, does not. Its conclusions are unreliable and should not be considered a basis for policy or investment.

Dr. Frank concludes that if CO_2 avoidance is valued at \$50/T and natural gas at not much over \$16/million BTU, "the net benefits of new nuclear, hydro, and natural gas combined cycle plants far outweigh the net benefits of new wind or solar [PV] plants. Wind and solar power are very costly from a societal perspective because of their very high capacity cost, their very low capacity factors, and their lack of reliability." Thus he implies that the quarter-trillion dollars invested in >80 GW of nonhydro renewables in each of the past three years got misallocated, and should have gone to the technologies they beat in the marketplace—most of all to nuclear power, none of whose 60-odd units under construction worldwide has withstood fair competition, been bid into a power auction, or been able to elicit unconscripted private capital.

As I'll describe in a forthcoming paper with my colleague Titiaan Palazzi, and consistent with his sensitivity-testing reported on p. 1 above, correct analysis reaches the opposite conclusions: new nuclear or combined-cycle gas capacity is not the most but the least effective way to displace coal power; wind and PVs are not the least but the most effective carbon-savers (except efficiency and most cogeneration, both of which Dr. Frank omits); and broadly similar findings apply to operational dispatch of old electrical resources. The market, even using levelized costs or pure profit motive, got it about right for effective carbon savings too. There is no theoretical necessity for cost and value approaches to yield the same priorities, but in this aspect of climate-protection investment and policy, they do.

I warmly invite specific and reasoned critiques of these remarks. Please send your suggestions for improvement to ablovins@rmi.org, cc tpalazzi@rmi.org. Thank you. — ABL