TAKE-OR-PAY CRISIS V2.0: WHAT WIND POWER GENERATORS AND PROVIDERS FAILED TO LEARN FROM GAS PIPELINES' 1980 DILEMMA

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## I.	INTRODUCTION

In the 1970s and early 1980s, natural gas pipelines, trying to correct for severe gas shortages in the 1970s, promised to "take-or-pay" for 80% or more of a producer's gas at the maximum lawful regulated price for terms of at least ten years.[1] By promising to pay a high price for a long term, pipelines would ensure continued investment in new gas exploration and production, and hence, a steady supply of natural gas to meet customer demand.[2] At the same time, however, pipelines assumed all the risk of market decline.[3] As the Fifth Circuit explained,

> The purpose of the take-or-pay clause is to apportion the risks of natural gas production and sales between the buyer and seller. The seller bears the risk of production. To compensate seller for that risk, buyer agrees to take, or pay for if not taken, a minimum quantity of gas. The buyer bears the risk of market demand. The take-or-pay clause insures that if the demand for gas goes down, seller will still receive the price for the Contract Quantity delivered each year.[4]

Within a few years, these pipelines were suffering for their mistake. The economic recession, cheap alternative fuels, increased supply, and unusual weather patterns reduced

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1. John Burrit McArthur, *Antitrust in the New [De]Regulated Natural Gas Industry*, 18 ENERGY L.J. 1, 14–15 (1997) [hereinafter *Antitrust in the New [De]Regulated Natural Gas Industry*]. *See generally* J. Michael Medina et al., *Take or Litigate: Enforcing the Plain Meaning of the Take-or-Pay Clause in Natural Gas Contracts*, 40 ARK. L. REV. 185 (1987) (discussing the impetus for and result of take-or-pay contracts); Jerome J. McGrath, *Natural Gas, in Turmoil and Transition*, 5 J. ENERGY L. & POL'Y 197, 206–08 (1984) (explaining take-or-pay provisions and their effect on natural gas prices).

2. *Antitrust in the New [De]Regulated Natural Gas Industry*, *supra* note 1, at 14; *see also* Charles A. Moore & Patrick Rock, *Ratemaking Treatment for Pipeline Take-or-Pay Costs*, NAT. GAS, Mar. 1987, at 8, 8 ("Pipelines assumed take-or-pay obligations in exchange for the assurance of a long-term gas supply to avoid curtailment problems, and to enable them to manage their load efficiently across the pipeline network.").

3. *Antitrust in the New [De]Regulated Natural Gas Industry*, *supra* note 1, at 15.

4. Universal Res. Corp. v. Panhandle E. Pipe Line Co., 813 F.2d 77, 80 (5th Cir. 1987).

demand and, therefore, depressed natural gas prices.[5] Take-or-pay prices remained 20% or more above the price of new natural gas.[6] The pipelines that were stuck with take-or-pay contracts could not purchase cheaper gas without breaching their contracts, and at the price for which they offered to sell gas, they could not unload their supplies, either.[7] Accordingly, most interstate pipelines refused to perform their take-or-pay contracts, opting instead to allow producers to sue for performance.[8] By 1989, the Federal Energy Regulatory Commission (FERC) calculated that more than $44 billion in take-or-pay liabilities had been settled—to the tune of 14.6 cents on the dollar.[9]

Wind power generators do not appear to have learned from their predecessors' mistakes. Wind producers are, like gas

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5. *See* Hanover Petrol. Corp. v. Tenneco, 521 So. 2d 1234, 1237 (La. Ct. App. 1988) (listing several of the reasons for price decrease, including the recession, the federally mandated natural gas pricing scheme, cheap competitive fuels, and the mild 1982–1983 winter); *see also* Hartman v. El Paso Natural Gas Co., 763 P.2d 1144, 1145 (N.M. 1988) (listing the same reasons for a drop in demand). Natural gas continues to be less expensive than some other fuels. *See* Giancarlo Guardia Gonzalez, *The Camisea Project: Developing Legal Frameworks for Avoiding Social and Environmental Conflicts in Sensitive Areas*, 31 HOUS. J. INT'L L. 213, 236 (2009).

6. *See Monthly U.S. Natural Gas Wellhead Price*, ENERGY INFO. ADMIN., http://tonto.eia.doe.gov/dnav/ng/hist/n9190us3m.htm (last visited Nov. 21, 2010) (showing that between 1985 and 1986, when deregulation occurred, natural gas prices dropped by more than 20%); *Antitrust in the New [De]Regulated Natural Gas Industry*, *supra* note 1, at 16.

7. *See Antitrust in the New [De]Regulated Natural Gas Industry*, *supra* note 1, at 15–17.

8. John Buritt McArthur, *The Take-or-Pay Crisis: Diagnosis, Treatment, and Cure for Immorality in the Marketplace,* 22 N.M. L. REV. 353, 424–27 (1992) [hereinafter *Take-or-Pay Crisis*]. The Federal Energy Regulatory Commission (FERC) corrected for most of the regulatory problems that allowed for the take-or-pay crisis by deregulating prices at the wellhead with Order No. 380, turning pipelines into open access essential facilities with Order no. 436, establishing a procedure for dealing with stranded take-or-pay costs with Order No. 500, and unbundling transmission services with Order No. 636. *Antitrust in the New [De]Regulated Natural Gas Industry*, *supra* note 1, at 17–20.

9. Order No. 500-H, Regulation of Natural Gas Pipelines After Partial Wellhead Decontrol, 53 Fed. Reg. 52,344, 52,356 (1989); *see Take-or-Pay Crisis*, *supra* note 8, at 356, nn.4 & 9 (stating that individual judgments ranged from $50 million in Forest Oil Corp. v. Oneok, Inc., No. C-84-197 (Tex. Dist. Ct. May 30, 1984) to more than $600 million in Kimball v. Tenneco, Inc., No. 27,880-S (Tex. Dist. Ct. Dec. 1, 1988).

producers in the 1970s and 1980s, entering into long-term, fixed price, take-or-pay contracts with electricity providers.[10] A recent Wind Power Purchase Agreement (WPPA) highlights their folly: a fifteen-year term during which providers agree to take up to 115% of 465,000 megawatt hours (MWh) at $50.00/MWh on-peak during the peak season, $45.00/MWh on-peak during the non-peak season, and $40.00/MWh off-peak.[11] After the generator has delivered 115%, the provider agrees to take additional energy at 90% of the contract price.[12] Furthermore, the provider agrees to take-or-pay for 97% of total generation, with minimum takes of 60% in the first year and 70% for every year thereafter.[13] For each MWh of untaken electricity, even where curtailment is a factor, the provider agrees to pay liquidated damages equal to 90% of the contract price plus the prevailing production-tax credit (PTC)–which the generator would usually receive from the federal government as a tax credit—making it more expensive for the provider to pay than to take delivery.[14] Essentially, then, although there is no minimum requirement, the provider agrees to pay a fixed rate, in one way or another, for almost every MWh the wind generator produces.

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10. Brit T. Brown & Benjamin A. Escobar, *Wind Power: Generating Electricity and Lawsuits*, 28 ENERGY L.J. 489, 499 (2007); *see* Richard R. Bradley, *Over the River and (Around) the Woods to Grandma's House We Go: Long-Term Firm Transmission Rights, Transmission Market Power, & Gaming Strategies in a Deregulated Energy Market—An International Comparison*, 30 HOUS. J. INT'L L. 327, 378 n.228 ("Under current transmission pricing, most generation is sold through take-or-pay, capacity-based transmission charges to reserve firm capacity.") (quoting ENERGY INFO. ADMIN., U.S. DEP'T OF ENERGY, RENEWABLE ENERGY ANNUAL 1998 ISSUES AND TRENDS: TRANSMISSION PRICING ISSUES FOR ELECTRICITY GENERATION FROM RENEWABLE RESOURCES 10 (1998)).

11. Internal document (on file with author).

12. *Id.*

13. *Id.*

14. *Id.* The PTC, a tax credit to subsidize wind power generation, was $21/MWh in 2010; the credit will remain in place until 2012. *See* American Recovery and Reinvestment Act of 2009, Pub. L. 111-5, § 1101, 123 Stat. 115, 516. The provider gets every Renewable Energy Credit (REC) regardless of whether it takes or pays. *See infra* note 32 and accompanying text. *Cf.* Emergency Motion for an Expedited Order on Curtailment Issues in SCE's 2010 RPS Procurement Plan, Docket RM08-08-009 at 8 (Fed. Energy Reg. Comm'n Aug. 21, 2008) (noting that, without a requirement that the provider pay for curtailed energy, the contract was not a true take-or-pay contract).

If a spate of litigation were to break out over breached take-or-pay clauses in WPPAs, however, damages are unlikely to be settled for mere pennies on the dollar.[15] Unlike natural gas, untaken wind energy cannot be stored and resold at a later date; it just disappears.[16] Where untaken gas retains its value, allowing for at least a portion of its costs to be recovered regardless of when the gas is purchased, the portion of costs to be recovered with the sale of wind energy is totally lost.[17] Wind power generators cannot therefore recover their losses.[18] Accordingly, a court would likely grant wind generators damages sufficient to cover their average costs, which are substantially more than mere pennies on the dollar.[19]

This potential problem is not limited to U.S. markets. Although the test case for the looming litigation played out in U.S. courts, companies in countries around the world have entered into long-term, fixed-cost, take-or-pay power purchase agreements with wind generators that create artificial

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15. *See supra* note 9 and accompanying text.

16. ALLIANCE BERNSTEIN, UTILITY SECTOR ANALYSIS: US WIND POWER SPINS INTO HIGH GEAR 2 (2009), https://www.bernstein.com/CmsObjectPC/pdfs/ B64578_WindPower_WP_091102.pdf; s*ee also* W. KIP VISCUSI, JOHN M. VERNON & JOSEPH E. HARRINGTON, JR., ECONOMICS OF REGULATION AND ANTITRUST 396 (2d ed. 1995) (discussing the near-impossibility, due to cost and other factors, of storing electricity for any significant period of time).

17. ALLIANCE BERNSTEIN, *supra* note 16, at 7. Energy costs, especially in a new generation facility, are measured according to average cost—or the cost required to pay for each unit of output, or MWh. *See* VISCUSI, VERNON & HARRINGTON*, supra* note 16, at 415 (discussing average cost pricing for electric utilities). Average cost is the total cost (variable cost plus fixed cost) of producing all output of an item, divided by the number of items produced. *Id.* at 392–96. For each additional item produced, the average cost of producing that item is reduced. *Id.* In a new wind generator, which has zero variable costs because wind is free, the average cost reflects the fixed costs of producing energy. ALLIANCE BERNSTEIN, *supra* note 16, at 7.

18. *See* ALLIANCE BERNSTEIN, *supra* note 16, at 2. *See generally* J. GREGORY SIDAK & DANIEL F. SPULBER, DEREGULATORY TAKINGS AND THE REGULATORY CONTRACT 475 (2d ed. 1998) (noting that the ability to remarket natural gas meant that many losses from breached take-or-pay clauses could be covered by resale).

19. *See* Order No. 500-H, *supra* note 9, at 52,356. Otherwise, the court would encourage providers to breach their contracts while denying generators cost recovery, possibly rendering them bankrupt and disincentivizing all future investment in wind generation. *See generally Take-or-Pay Crisis, supra* note 8, at 356 (considering the repercussions of take-or-pay contracts in the natural gas context).

electricity prices.[20] This is especially clear in the European Union, which has set a goal of obtaining 20% of its energy from renewable sources by 2020.[21] European wind generators almost always require long-term, take-or-pay power agreements,[22] and large natural gas finds in Russia and old Soviet Bloc countries are flooding the European market with natural gas.[23] These factors, along with high prices for wind energy, could lead many providers to breach their contracts.[24] The use of take-or-pay contracts in the wind energy industry is therefore one of global

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20. *See, e.g.*, Randall Denley, *Those Political Winds Keep Blowing*, OTTAWA CITIZEN, Sept. 10, 2010, *available at* http://www.ottawacitizen.com/technology/Those+political+winds+keep+blowing/3480665/story.html (discussing the increased price of electricity due to take-or-pay wind contracts in Canada); Terence Creamer, *Eskom Gets Set to Open Bidding Process for 1,025 MW of Renewables*, ENGINEERING NEWS, Sept. 7, 2010, *available at* http://www.engineeringnews.co.za/article/eskom-gets-set-to-open-bidding-process-for-1-025-mw-of-renewables-2010-09-07 (discussing new wind power and other renewable projects that will have take-or-pay agreements that will reduce incentives for the South African state-owned power utility, Eskom, to price shop); Angus Johnston, Amalia Kavali & Karsten Neuhof, *Take-or-Pay Contracts for Renewables Deployment*, 36 ENERGY POL'Y 2481, 2484–85 (2008) (proposing take-or-pay provisions in Europe to help Europe meet its 20% target for renewable energy, recover their investment while not burdening consumers with increased electricity prices). In this very issue of the Houston Journal of International Law, Michael Streich examines the similar concept of Ontario's feed-in tariffs for wind power. Michael Streich, Comment, *Green Energy and Economy Act, 2009: A "FIT"-ing Policy for North America?*, 33 HOUS. J. INT'L L. 419 (2011).

21. Marvin C. Bynum, Comment, *Testing the Waters: Assessing Wisconsin's Regulatory Climate for Offshore Wind Projects*, 93 MARQ. L. REV. 1533, 1543 (2010).

22. *See* JEREMY PARKES & ANDREW TINDAL, FORECASTING SHORT TERM WIND FARM PRODUCTION IN COMPLEX TERRAIN 1 (2006), *available at* http://*www.2004ewec.info/files/23_1400_jeremyparkes_01.pdf* (discussing the proliferation of wind farms that require take-or-pay agreements).

23. *See* Press Release, Hong Kong Trade Development Council, CNPC Discovers Major Gas Field in Turkmenistan (Sept. 30, 2010), *available at* http://www.hktdc.com/info/vp/a/intmk/en/1/3/1/1X074NPE/International-Markets/CNPC-discovers-large-gas-filed-in-Turkmenistan.htm (discussing large gas finds in Turkmenistan); *see also* Kim Talus, *Access to Gas Markets: A Comparative Study on Access to LNG Terminals in the European Union and the United States*, 31 HOUS. J. INT'L L. 343, 362 (2009) (noting that Russia exported a total of 114,321 million cubic meters of natural gas to the European Union in 2006).

24. European researchers have discussed take-or-pay provisions that would mitigate the artificiality of prices while ensuring wind generators a fair rate of return. *See* Johnston, Kavali & Neuhoff, *supra* note 20, at 2485 (proposing take-or-pay provisions that will help align wind power with general market prices).

concern and one that, without quick resolution, could lead to higher prices, bankrupt wind generators, and slower development of the burgeoning renewable energy industry.

This article looks at the problem of long-term, fixed-cost, take-or-pay provisions in WPPAs. First, it finds justification for some form of take-or-pay agreement in WPPAs, acknowledging the importance of balancing risk to encourage long-term investment in renewable technologies. Second, it discusses looming technological and regulatory changes that carry the potential to boost each generator's available capacity by 20% or more. This increased capacity will reduce current wind energy costs by at least 20%, enabling new generators to undercut the market, and, potentially, to price existing generators with long-term, fixed-cost, take-or-pay agreements out of the market. Finally, this paper offers suggestions for new and existing WPPAs, ranging from contract negotiations and renegotiations to anticipatory breach. In the end, it concludes that, unless proactive steps are taken today, a pitched battle between wind generators and providers will usher in an era of new (but familiar) FERC regulation.

II.   WHY TAKE-OR-PAY MAKES SENSE

As the Fifth Circuit explained in *Universal Resources*, take-or-pay provisions are useful for energy generators that would otherwise hold a disproportionate share of the risk of loss.[25] In order to incentivize production, the take-or-pay provision apportions the risk so that the generator can guarantee it will cover its capital costs.[26] Without this guarantee, no one would invest in new wind projects because current economics do not support a market-based model.[27]

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25. *See* Universal Res. Corp. v. Panhandle E. Pipe Line Co., 813 F.2d 77, 80 (5th Cir. 1987). However, as long as transmission constraints strand wind generators' electricity, these generators will continue to hold a disproportionate share of the risk of loss. *See* TXU Portfolio Mgmt. Co. v. FPL Energy, LLC, 328 S.W. 3d 580, 587 (Tex. App.—Dallas 2010, no pet. h.) (holding wind generators liable for failing to deliver a contractually-required amount of electricity despite the generators' claims that a lack of transmission capacity was to blame).

26. *See Universal Res. Corp.*, 813 F.2d at 80.

27. *See, e.g.*, ALLIANCE BERNSTEIN, *supra* note 16, at 5 (showing that government

Within the jurisdiction of the Electric Reliability Council of Texas (ERCOT), the amount of energy demanded by customers is fairly constant.[28] For every megawatt (MW) of wind-generated power added to the grid, therefore, a MW of power generated by another fuel source is no longer needed.[29] In an efficient energy market, the first fuel source that will be backed down is the fuel source with the highest marginal cost per MWh.[30] As Chart 1 below shows, wind generation has zero marginal cost, while natural gas generation has the highest marginal cost.[31]

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incentives are essential to wind energy production and that political uncertainty and frequent expiration of PTCs and investment-tax credit (ITCs) have resulted in a "boom-and-bust cycle of development" of renewable energy sources like wind farms); *see* Johnston, Kavali & Neuhoff, *supra* note 20 at 2482 (advocating government involvement in renewable energy contracts to minimize risk and encourage investment).

28. BRENDAN KIRBY, EVALUATING TRANSMISSION COSTS AND WIND BENEFITS IN TEXAS: EXAMINING THE ERCOT CREZ TRANSMISSION STUDY 13–14 (2007), http://www.consultkirby.com/files/Evaluating_Transmission_Costs_In_Texas.pdf [hereinafter EVALUATING TRANSMISSION COSTS AND WIND BENEFITS IN TEXAS].

29. *Id.* at 13.

30. *Id. See* VISCUSI, VERNON & HARRINGTON, *supra* note 16, at 396–99 (discussing the costs of power production and describing marginal cost pricing).

31. The Department of Energy (DOE) predicts that natural gas costs will not increase over the next twenty years due to the large shale reserves being developed and the potential for Alaskan gas to be delivered to markets in the lower forty-eight states, which will simultaneously increase domestic supply and decrease gas imports. *See* U.S. ENERGY INFO. ADMIN., ANNUAL ENERGY OUTLOOK 2010 WITH PROJECTIONS TO 2035 42 (2010) http://www.eia.gov/oiaf/archive/aeo10/pdf/0383(2010).pdf [hereinafter ANNUAL ENERGY OUTLOOK 2010]. For a more detailed examination of the "significant impact" of shale gas, see Susan Sakmar's article in this issue of the Houston Journal of International Law. *See* Susan L. Sakmar, *Global Shale Gas Initiative: Will The United States Be The Role Model For The Development of Shale Gas Around The World?*, 33 HOUS. J. INT'L L. 369 (2011). Accordingly, the average cost of gas generators will remain fairly constant for the foreseeable future. However, as I argue later in this paper, and as recent market prices establish, this number may be unrealistically high. *See infra* notes 49–55, 122–31 and accompanying text.

Chart 1[32]

Marginal Cost of Providing Electricity ($2008/MWh]
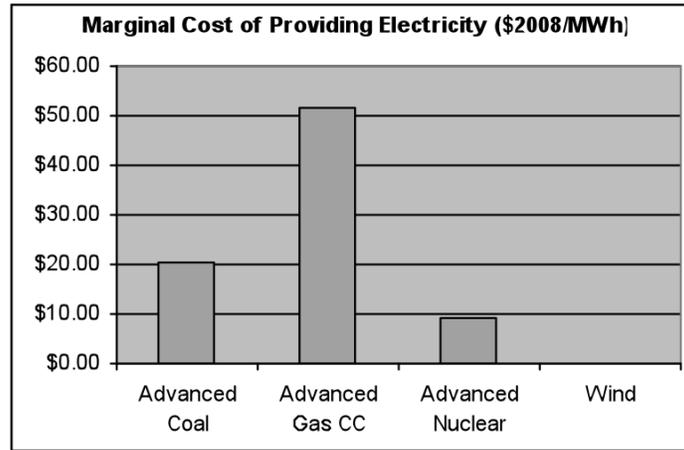
However, although wind is cheaper than each of the other fuel sources, it has not displaced their use in the Texas market.[33] This inefficiency may be attributed to two facts: First, wind generation is intermittent, with better generation during off-peak hours at night when the wind blows.[34] Second, most existing dispatchable generators—including the majority of coal, gas, and nuclear generators in Texas—have already fully recovered their capital costs, but wind projects are only beginning to recover their capital costs.[35] In reality, then, the

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32. STEVEN H. LEVINE, FRANK C. GRAVES & METIN CELEBI, PROSPECTS FOR NATURAL GAS UNDER CLIMATE POLICY LEGISLATION: WILL THERE BE A BOOM IN GAS DEMAND? 3 (2010) http://*www.brattle.com/_documents/UploadLibrary/Upload839.pdf;* ALLIANCE BERNSTEIN, *supra* note 16, at 7; BRANDON BLOSSMAN, BECCA FOLLOWILL & JESSICA CHIPMAN, TEXAS WIND GENERATION 40 (2009) http://www.tudorpickering.com/ pdfs/TPH.Texas.Wind.Generation.Report.August.2009.pdf. In the chart, the marginal cost represents variable operations and management (O&M), which takes into account the DOE's levelized costs of fuel and transmission for each additional MWh generated. The chart assumes Henry Hub gas prices of $5.00 per million British Thermal Unit (MMbtu), coal prices of $1.50/MMbtu, uranium prices of $41.50/lb of U_3O_8, and a 2MW wind turbine cost of $2,000/KW with a capacity of 35%.

33. *See* EVALUATING TRANSMISSION COSTS AND WIND BENEFITS IN TEXAS, *supra* note 27, at 14 fig.6 (illustrating current transmission trends in Texas).

34. *See infra* notes 89–91 and accompanying text.

35. *See* ALLIANCE BERNSTEIN, *supra* note 16, at 7. If no generation existed and generators from each fuel source were being simultaneously introduced into the market,

Texas electricity market is better reflected by Chart 2 below, which compares fully cost-recovered, non-renewable fuel-source generators with new wind generators operating at average cost.[36]

Chart 2[37]
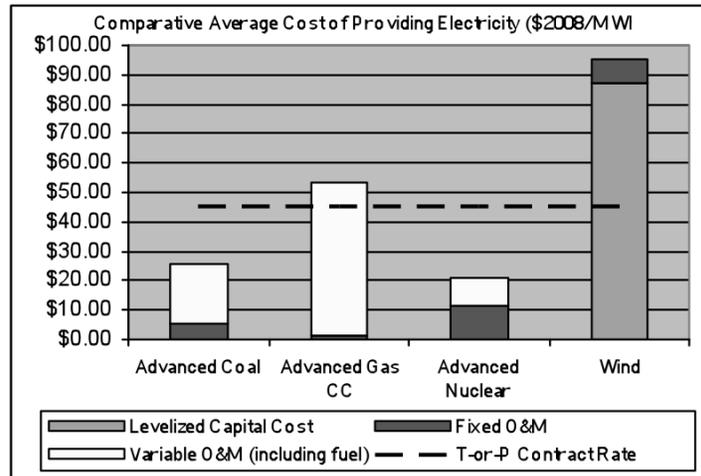
As should be evident, wind generators, on their own, cannot currently compete in the Texas market and cover their costs. Nevertheless, two factors have enabled wind power to become

wind generators, which cost about $2000 per KW to build, would beat out nuclear generators, which cost about $2800 per KW to build, but would lose out significantly to gas and coal generators, which each cost less than $800 per KW to build. *See id.* at 7–8.

36. *See* BLOSSMAN, FOLLOWILL & CHIPMAN, *supra* note 31, at 40 (noting that the average ERCOT power price is $40/MWh, ranging from about $50/MWh on-peak to $35/MWh off-peak). Looking at the comparative costs of gas generators, which are more heavily relied on during on-peak hours due to their quick dispatchability, and coal and nuclear generators, which are more heavily relied on during off-peak hours because of their slow ramping capabilities, the price difference between on-peak and off-peak hours makes sense. *See id.* at 16.

37. ANNUAL ENERGY OUTLOOK 2010, *supra* note 30; LEVINE, GRAVES & CELEBI, *supra* note 31, at 3–4; ALLIANCE BERNSTEIN, *supra* note 16, at 7, BLOSSMAN, FOLLOWILL & CHIPMAN, *supra* note 31, at 40. The chart assumes Henry Hub gas prices of $5.00/MMbtu, coal prices of $1.50/MMbtu, uranium prices of $41.50/lb of U_3O_8, and a 2MW wind turbine cost of $2,000/KW with a capacity of 35%. It also assumes a long-term, take-or-pay contract rate of $45.00, recognizing that, in long-term, take-or-pay contracts, parties stick as close to average cost pricing as possible.

competitive: government subsidies and the market price of natural gas.[38] A third factor, a carbon cost per ton that will apply to coal and natural gas generators, will make wind power even more competitive.[39] As long as the market remains competitive, providers will be able to pass their costs onto end-users.[40] They will therefore remain willing to sign long-term take-or-pay contracts with generators;[41] and as long as generators know they will cover their investment costs, they will continue to develop new wind projects.[42]

A. *Government Subsidies*

Federal and state governments have designed several mechanisms to subsidize the construction and expansion of wind capacity in the Texas market. The first of these mechanisms provides for either a $21 PTC/MWh for the first ten years of operation, an investment-tax credit (ITC) equal to 30% of qualifying costs, or a cash grant equal to 30% of approved construction costs for new wind projects.[43] For projects coming online during 2012 and 2013, the latter two credits deliver about $30/MWh in cost savings in 2008 dollars.[44]

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[38]. LEVINE, GRAVES & CELEBI, *supra* note 31, at 4; ALLIANCE BERNSTEIN, *supra* note 16, at 5.

[39]. LEVINE, GRAVES & CELEBI, *supra* note 31, at 3; *see* Jessie S. Lotay, *Subprime Carbon: Fashioning an Appropriate Regulatory and Legislative Response to the Emerging U.S. Carbon Market to Avoid a Repeat of History in Carbon Structured Finance and Derivative Instruments*, 32 HOUS. J. INT'L L. 459, 487 (2010).

[40]. *See* Johnston, Kavali & Neuhoff, *supra* note 20, at 2483–84.

[41]. *See id.*

[42]. *See id.* at 2494–95.

[43]. *See* American Recovery and Reinvestment Act of 2009, Pub. L. 111-5, § 1101, 123 Stat. 115, 516; MARK BOLINGER ET AL., NAT'L RENEWABLE ENERGY LAB., PTC, ITC, OR CASH GRANT? AN ANALYSIS OF THE CHOICE FACING RENEWABLE POWER PROJECTS IN THE UNITED STATES 4–5 (2009) http://eetd.lbl.gov/ea/emp/reports/lbnl-1642e.pdf. This analysis assumes a 2 MW wind turbine at $2000/KW cost with 35% capacity.

[44]. *See* American Recovery and Reinvestment Act of 2009 § 1101. A crediting mechanism of equivalent value has been in place since passage of the Energy Policy Act of 1992, and has been extended four times thus far. ALLIANCE BERNSTEIN, *supra* note 16, at 5; *see also* BLOSSMAN, FOLLOWILL & CHIPMAN, *supra* note 31, at 40 (noting that the ITC reduces the cost per MWh by about $30). The decision about whether to choose the PTC, ITC, or 30% cash grant in lieu of the ITC, depends on the cost of building a wind project and its expected generation capacity. The ITC and the cash grant both reduce the

The second mechanism permits a five-year accelerated depreciation schedule—referred to as the Modified Accelerated Cost Recovery System (MACRS) by the Internal Revenue Service—to capture 50% of total value, which translates to savings of about 10%, or $10 per MWh.[45] The third mechanism provides for Renewable Energy Credits (REC), which wind generators sell to non-renewable generators, and which are currently priced at about $10 per MWh.[46] When these three subsidies are compounded—assuming the generator selects either the ITC or the cash grant—they amount to a discount per MWh of about $50 in 2008 dollars.[47] As shown in Chart 3 below, these subsidies bring down wind power's rate per MWh below the rate for gas-generated power. Not surprisingly, then, wind power has displaced gas generation on a nearly MWh-to-MWh basis in ERCOT.[48]

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depreciable basis, while the PTC does not. Accordingly, an ITC or cash grant is better for 30–35% capacity projects costing $2000 or more per KW, while a PTC delivers more value for projects costing less than $2000 per KW or for any project operating at more than 40% capacity. *See* BOLINGER ET AL., *supra* note 42, at 6. This analysis assumes a 2 MW wind turbine at $2,000/KW cost with 35% capacity.
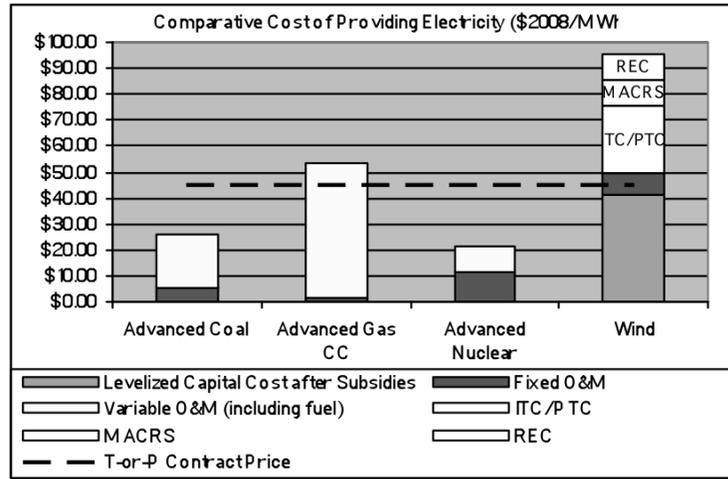
45. *See Figuring Depreciation under MACRS*, DEP'T OF THE TREASURY, INTERNAL REVENUE SERV., http://www.irs.gov/publications/p946/ch04.html#d0e4096 (last visited Nov. 21, 2010); *see also* BLOSSMAN, FOLLOWILL & CHIPMAN, *supra* note 31, at 40. This analysis assumes a 2 MW wind turbine at $2,000/KW cost with 35% capacity.

46. 16 Tex. Admin. Code § 25.173 (2009) (outlining REC trading programs, which allow renewable generators to earn RECs, which they sell to nonrenewable generators)*;* BLOSSMAN, FOLLOWILL & CHIPMAN, *supra* note 31, at 16 (noting the average REC price of $10/MWh).

47. *See* BLOSSMAN, FOLLOWILL & CHIPMAN, *supra* note 31, at 40. This analysis assumes a 2 MW wind turbine at $2,000/KW cost with 35% capacity. *See id.*

48. *See* Russell Gold, *Natural Gas Tilts at Windmills in Power Feud*, WALL ST. J., Mar. 2, 2010, *available at* http://online.wsj.com/article/SB10001424052748704188104575 083982637451248.html.

Chart 3[49]

Comparative Cost of Providing Electricity ($2008/MWh)

From a contract standpoint, however, the subsidies create weird incentives for providers. On the one hand, subsidies such as the ITC, the cash grant, the MACRS depreciation schedule, and the RECs ensure a lower competitive rate for all wind energy purchased over the life of the contract.[50] Each of these subsidies is either fixed or earned according to the amount of energy generated—as opposed to the amount of energy delivered—and so is consistent regardless of whether the provider takes or pays for a generator's output.[51] A contract that takes into account these subsidies should encourage a provider to determine the best estimate of a wind generator's output

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49. ANNUAL ENERGY OUTLOOK 2010, *supra* note 30; LEVINE, GRAVES & CELEBI, *supra* note 31, at 3; BLOSSMAN, FOLLOWILL & CHIPMAN, *supra* note 31, at 40; ALLIANCE BERNSTEIN, *supra* note 16, at 7. The chart assumes Henry Hub gas prices of $5.00/MMbtu, coal prices of $1.50/MMbtu, uranium prices of $41.50/lb of U_3O_8, and a 2MW wind turbine cost of $2,000/KW with a capacity of 35%, and wind energy subsidies of a 30% ITC, five-year accelerated depreciation with 50% of value captured, and $10/MWh REC. The subsidies detract from the levelized capital cost. *See supra* note 31 and accompanying text. It also assumes a long-term, take-or-pay contract rate of $45.00, recognizing that, in long-term, take-or-pay contracts, parties stick as close to average cost pricing as possible. *See* Johnston, Kavali & Neuhoff, *supra* note 20, at 2490.

50. *See generally Figuring Depreciation under MACRS*, *supra* note 44.

51. *See supra* notes 33–35 and accompanying text.

capacity in order to arrive at the lowest cost-of-service, and therefore the lowest contract price.[52]

On the other hand, the PTC subsidy, which only applies to every MWh produced *and* delivered, gives providers an incentive to overestimate a wind generator's output capacity when negotiating a fixed rate with a take-or-pay provision.[53] Otherwise, because providers are required by most take-or-pay provisions to pay generators the value of the PTCs that would have been realized if the provider had taken all of the generator's output, and because there is no maximum limit on the amount of output that must be taken or paid for, an underestimate of a generator's output would force the provider to pay 150% of the contract price for each MWh generated that exceeds expectations, causing the provider to lose money.[54] When providers overestimate the output capacity, they underestimate the cost of service.[55] This insufficient cost-of-service estimate decreases the contract rate, establishing an artificially low cost per MWh.[56] Accordingly, wind generators will likely shy away from the PTC, even though it could deliver significant cost savings if generation becomes more efficient.[57]

Notwithstanding the perverse contract incentives the subsidies create from a take-or-pay perspective, wind power will remain competitive in the Texas market as long as the subsidies continue.[58] Additionally, by incentivizing the cash grant over the PTC, they ensure that generators immediately cover 30% of

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52. *See* VISCUSI, VERNON & HARRINGTON, *supra* note 16, at 398–99 (noting that energy prices reflect the cost of providing service).

53. *See supra* notes 10–14 and accompanying text.

54. *See supra* notes 10–14 and accompanying text. $21/MWh on top of a $40/MWh rate adds 50% to a provider's cost for each MWh purchased.

55. The next section, "The Gathering Storm," details and quantifies many of the costs of this overestimation. *See infra* notes 77–140 and accompanying text.

56. *Id.* The good aspect to the artificially high cost-of-service is that, with the PTC, it generates a substantially greater incentive for the development of the wind-power infrastructure. *See supra* note 14.

57. *See infra* notes 59–63 and accompanying text.

58. *See* ALLIANCE BERNSTEIN, *supra* note 16, at 5. But if any of the subsidies are scaled back or removed—as the PTC and ITC threaten to do every two years, barring Congressional action to extend them—wind generation could price itself out of the market. *Id.* at 5.

their costs while simultaneously reducing the risk of high-interest loans or other disincentives to investment.59 By apportioning these risks, take-or-pay clauses encourage continued investment in and development of new wind projects.

B. High Cost of Natural Gas

The price volatility of natural gas contributes significantly to wind power's competitiveness.60 The cost of natural gas—about 10 million British Thermal Units (MMbtus) are required to produce one MWh of electricity in an advanced gas combine cycle generator—makes up more than 70% of the cost of gas-fired generation.61 Accordingly, for every $1 shift in the cost of natural gas, the cost of gas-fired generation shifts in the same direction $10 per MWh.62 As Chart 4 below attests, electricity generated by $4/MMbtu63 gas is significantly more competitive with wind power than electricity generated by $8/MMbtu64 gas, especially when you account for gas generation's better dispatchability.65 But when gas sells for $8/MMbtu, as it did in 2008, its high price clearly justifies significant investment in

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59. BOLINGER ET AL., *supra* note 42, at 10–11.

60. *See* ALLIANCE BERNSTEIN, *supra* note 16, at 7; *see also* Martin Hunt & Erik Eisele, *Far from Disaster: Ukraine's Energy Sector Seeks Investment and Growth*, 31 HOUS. J. INT'L L. 243, at 257–58 (2009) (describing Ukraine's dire financial straits in 2008 "created by buying expensive Russian natural gas and reselling it at lower prices on the domestic market").

61. ALLIANCE BERNSTEIN, *supra* note 16, at 7.

62. *Id.* (showing that a Henry Hub gas price of $6.37/MMbtu yields a gas-fired generation cost of $61.83).

63. On April 29, 2010, Henry Hub gas prices were $3.80/MMbtu, with bearish expectations from some analysts that prices would drop another 10% before June 2010. *See* Energy Intelligence Grp., Inc., *Gas Market Reconnaissance*, NAT. GAS WEEK, June 29, 2010, *available at* http://www.energyintel.com/DocumentDetail.asp?document_id=668268.

64. The average Henry Hub price in 2008 was $7.96/MMbtu. *Natural Gas Summary*, U.S. ENERGY INFO. ADMIN., http://tonto.eia.doe.gov/dnav/ng/ng_sum_lsum_dcu_nus_a.htm (last visited Nov. 21, 2010) [hereinafter *EIA Natural Gas Summary*]. At $8/MMbtu, wind power would remain competitive with gas power even if most wind subsidies were withdrawn, notwithstanding that some subsidies, such as the ITC, cannot be withdrawn from existing projects.

65. *See infra* notes 85–86 and accompanying text.

and growth of viable wind projects.[66] This volatility would be a serious disincentive to investment in wind projects were it not for take-or-pay clauses that guarantee generators a return regardless of external market forces.

Chart 4[67]
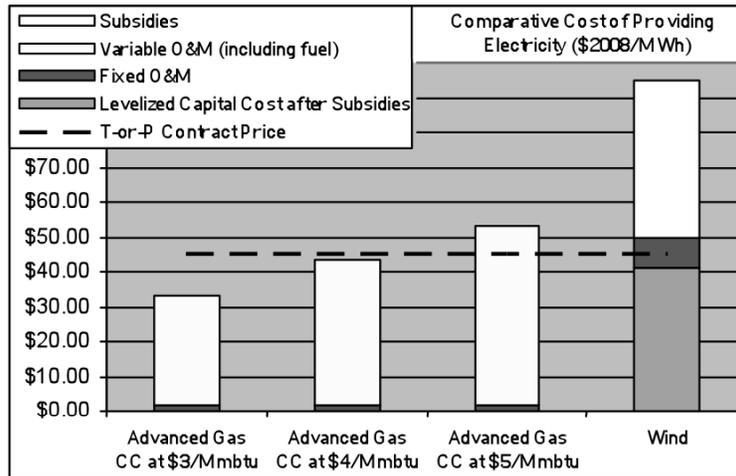
C. Carbon Tax

In June 2009, the U.S. House of Representatives passed climate change legislation that will, among other things, establish a market-based program that caps the amount of allowed carbon dioxide ("CO_2") emissions and creates tradable emission allowances ("cap-and-trade").[68] Allowance trading sets

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66. *See EIA Natural Gas Summary*, *supra* note 64.

67. ANNUAL ENERGY OUTLOOK 2010, *supra* note 30; LEVINE, GRAVES & CELEBI, *supra* note 31, at 3; BLOSSMAN, FOLLOWILL & CHIPMAN, *supra* note 31, at 40; ALLIANCE BERNSTEIN, *supra* note 16, at 7. The chart assumes Henry Hub gas prices of $5.00/MMbtu, and a 2MW wind turbine cost of $2000/KW with a capacity of 35%, and wind energy subsidies of a 30% ITC, five-year accelerated depreciation with 50% of value captured, and $10/MWh REC. The subsidies detract from the levelized capital cost. *See supra* note 31 and accompanying text. It also assumes a long-term, take-or-pay contract rate of $45.00, recognizing that, in long-term, take-or-pay contracts, parties stick as close to average cost pricing as possible. *See* Johnston, Kavali & Neuhoff, *supra* note 20, at 2490.

68. American Clean Energy & Security Act of 2009, H.R. 2454, 111th Cong. § 724 (2009); John M. Broder, *House Passes Bill to Address Threats of Climate Change*, N.Y.

a price for CO_2 emissions, acting as a surcharge (or penalty) on fossil fuel consumption.[69]

The CO_2 price will significantly increase the cost of coal and gas generation.[70] Coal generators, which emit roughly one ton of CO_2 per MWh, will see their costs increase $1 per MWh for every increase of $1 per ton of CO_2.[71] Gas generators, which emit about 0.4 tons of CO_2 per MWh, will see their costs increase $0.40 per MWh for every increase of $1 per ton of CO_2.[72] Accordingly, a $30 per ton[73] CO_2 price will increase the cost of coal generation by $30 per MWh and will increase the cost of gas generation by $12 per MWh. As Chart 5 below shows, as long as wind subsidies remain in place, a $30 per ton CO_2 price drives up the cost of coal and gas generators above that of wind power, even when gas is priced at $3/MMbtu.

TIMES, June 27, 2009, at A1 (noting that the bill passed by a vote of 219 to 212). Similar Legislation in the Senate was abandoned in mid-2010. *Comprehensive Energy Bill Dies in Senate*, CBS NEWS, July 22, 2010, http://www.cbsnews.com/stories/2010/07/22/politics/main6703205.shtml.
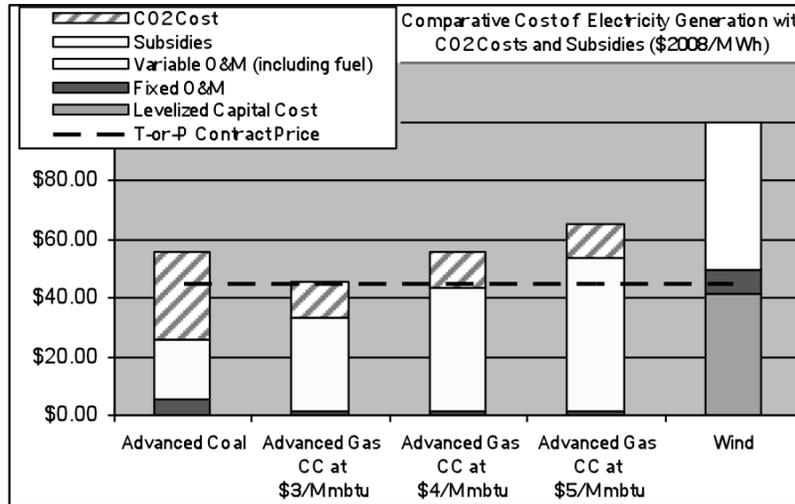
69. LEVINE, GRAVES & CELEBI, *supra* note 31, at 3.

70. *Id.*; *see* Luis E. Cuervo, *OPEC: From Myth to Reality*, 30 HOUS. J. INT'L L. 433, 454 (2008) (arguing that "carbon pricing will play a crucial role in the closing years of the hydrocarbon age").

71. LEVINE, GRAVES & CELEBI, *supra* note 31, at 3.

72. *Id.*

73. *Id.* $30 per ton appears to be the price most observers expect. *Id.*

Chart 5[74]

Comparative Cost of Electricity Generation with CO2 Costs and Subsidies ($2008/MWh)

Legend: CO2 Cost; Subsidies; Variable O&M (including fuel); Fixed O&M; Levelized Capital Cost; T-or-P Contract Price

Categories: Advanced Coal; Advanced Gas CC at $3/Mmbtu; Advanced Gas CC at $4/Mmbtu; Advanced Gas CC at $5/Mmbtu; Wind

Cap-and-trade is not a done deal, however.[75] Without it, subsidized wind power will compete with gas-fired generators when gas is $4 or more per MMbtu. But it will lose ground

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74. ANNUAL ENERGY OUTLOOK 2010, *supra* note 30; LEVINE, GRAVES & CELEBI, *supra* note 31, at 3; BLOSSMAN, FOLLOWILL & CHIPMAN, *supra* note 31, at 40; ALLIANCE BERNSTEIN, *supra* note 16, at 7. The chart assumes Henry Hub gas prices of $5.00/MMbtu, coal prices of $1.50/MMbtu, uranium prices of $41.50/lb of U_3O_8, and a 2MW wind turbine cost of $2000/KW with a capacity of 35%, and wind energy subsidies of a 30% ITC, five-year accelerated depreciation with 50% of value captured, and $10/MWh REC. The subsidies detract from the levelized capital cost. *See supra* note 31 and accompanying text. It also assumes a long-term, take-or-pay contract rate of $45.00, recognizing that, in long-term, take-or-pay contracts, parties stick as close to average cost pricing as possible. *See* Johnston, Kavali & Neuhoff, *supra* note 20, at 2490.

75. *See* John M. Broder, *'Cap and Trade' Loses Its Standing as Energy Policy of Choice*, N.Y. TIMES, Mar. 25, 2010, at A13 (addressing the demise of "cap-and-trade" policy discussion in Washington); Alex Kaplun, *Senate Panel Clears Budget but Nips Climate Reconciliation*, N.Y. TIMES, Apr. 23, 2010, at E1 (reporting that a recent amendment to the budget bill would prevent reconciliation for bills that cost more than 20% of a session's budget; the climate bill would likely cost more than 20%). If, for some reason, cap-and-trade is not implemented, other new policies, such as increased EPA enforcement or mandatory carbon-capture-and-sequestration, would likely increase the cost of coal and gas generation by large, but different, amounts. *See* Christian Parenti, *The Case for EPA Action,* NPR, Apr. 23, 2010, http://www.npr.org/templates/story/story.php?storyId=126129216.

against coal-fired generators and, if gas drops to \$3/MMbtu,[76] to gas-fired generators as well. The precariousness of these new laws and their effect on the electricity industry substantially justifies fixed-cost, take-or-pay provisions that cover wind generators' costs.

III. TAKE-OR-PAY MAKES SENSE, AT LEAST FOR NOW

Presently, fixed-cost, take-or-pay provisions appear to appropriately apportion risk, so that investment in new generation is encouraged and providers are assured a competitive rate. But, as the charts and analysis above have shown, even with subsidies, high gas prices, and a \$30 per ton CO_2 price, wind power is only just competitive enough—and as opposed to gas, coal, and nuclear power, the intermittent and at times unpredictable nature[77] of wind power creates costly disincentives to overreliance on the renewable fuel source. Slight variations in any of the three factors could price wind power out of the market as long as it remains at current rates—a risk that, because of fixed-cost, take-or-pay provisions, is borne entirely by providers.[78]

IV. THE GATHERING STORM

Similar to the confluence of factors that depressed gas prices in the early 1980s, a perfect storm of events are gathering on the horizon that will undercut demand for wind power generated according to fixed-rate, take-or-pay WPPAs.[79] Additional transmission capacity is being added to the grid every day, making room for new turbines with advanced technology[80] and

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76. *See supra* note 63 and accompanying text.

77. *See infra* note 104 and accompanying text.

78. *See infra* note 131 and accompanying chart (highlighting that, at least in the short term, wind power is currently the most expensive generation source).

79. *See* Adriene Hill, *U.S. Wind Power Slumps on Low Demand,* MARKETPLACE, July 27, 2010, http://marketplace.publicradio.org/display/web/2010/07/27/am-us-wind-power-slumps-on-low-demand/# (noting that, in spite of efforts to boost wind power production, demand for power, in general, is down).

80. *See, e.g., High-Capacity Turbines Produce More Wind Energy*, CBS: NETHERLANDS, June 28, 2007, http://www.cbs.nl/en-GB/menu/themas/industrie-energie/publicaties/artikelen/archief/2007/2007-2226-wm.htm (noting that wind turbines

cheaper, more prolific, and more efficient storage facilities, and requiring evolving regulations that fully account for the additional wind generation.[81] Furthermore, shale gas production and a potential Alaska gas pipeline will provide an abundance of alternative fuel supplies, which will drive down the costs of gas-powered generators.[82] All of these elements will combine to put existing WPPAs with fixed-cost, take-or-pay provisions at a significant cost disadvantage when compared to market prices for wind energy.

A. Additional Transmission Capacity

At the end of 2009, ERCOT had 9 GW of wind generation, which constituted 11% of installed capacity and 6% of energy produced in Texas.[83] Only 6.6 GW of transmission capacity existed, however.[84] Furthermore, due to congestion problems resulting from limited transmission routes and open access rules—with wind generators simultaneously trying to dump electricity onto the same lines—actual wind power output appears to be capped at about 4.5 GW.[85] Where wind generators

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installed after 2006 have used advanced technology to more than double prior turbines' output capacity). I did not model the impact of new wind turbines because I wanted to focus on cost reductions that all wind generators would experience.

81. *See, e.g.*, J. Scott Childs, *Continental Cap-and-Trade: Canada, the United States, and Climate Change Partnership in North America*, 32 HOUS. J. INT'L L. 393, 448–49 (2010) (noting the cooperative U.S.-Mexico legal framework aimed to improve electric transfer efficiency).

82. *See* BENJAMIN SCHLESINGER, INT'L ASS'N FOR ENERGY ECON., SHALE GAS, LNG AND RISING DEMAND-DRIVING GLOBAL GAS PRICES 15 (2010) (noting that North American shale gas developments have already impacted natural gas prices in Europe and will likely affect U.S. prices soon).

83. *ERCOT Quick Facts*, ELEC. RELIABILITY COUNCIL OF TEX., http://www.ercot.com/content/news/presentations/2010/ERCOT%20Quick%20Facts,%20Feb%202010.pdf.

84. PUB. UTIL. COMM'N OF TEX., SCOPE OF COMPETITION IN ELECTRIC MARKETS IN TEXAS 47 (2009), *available at* http://www.puc.state.tx.us/electric/reports/scope/2009/2009scope_elec.pdf [hereinafter PUCT]; *see also* Ramteen Shiosansi & David Hurlbut, *Market Protocols in ERCOT and their Effect on Wind Generation*, 38 ENERGY POL'Y 3192, 3196 (2010) ("One of the largest impediments to integrating wind generators into the ERCOT market is the geography of the state and access to transmission capacity").

85. ALLIANCE BERNSTEIN, *supra* note 16, at 10.

operate at an average capacity of about 35%, this cap does not usually create huge problems.[86]

Chart 6[87]
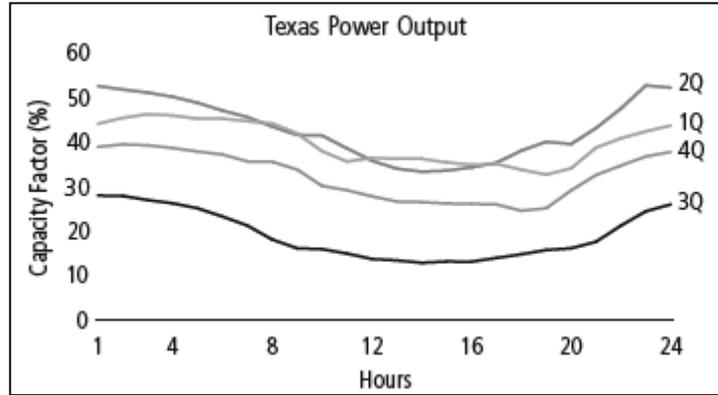
However, when the wind blows and generators operate at 50% or more, bottlenecks occur when everyone delivers their output to the grid at the same time.[88] To prevent these bottlenecks, generators are required to curtail output, even if their generation was scheduled.[89] These curtailments typically range between 500 and 1000 MW during the peak hour and occur on a daily basis.[90] On average, nearly 10% of all scheduled

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86. *Id.* at 3. Depending on the season, wind generates at between 20% and 40% capacity during on-peak, daytime hours, when the wind dies down, and between 30% and 60% capacity during off-peak, nighttime hours, when the wind blows. *See infra* note 91 and accompanying chart.

87. ALLIANCE BERNSTEIN, *supra* note 16, at 3.

88. *See* Shiosansi & Hurlbut, *supra* note 84, at 3193.

89. *See id.* ("The limited transmission capacity out of western Texas has been a bottleneck for generators"); *id.* at 3196 ("ERCOT's interconnection policy allows wind generators to connect to the power system even without sufficient transmission capacity to carry the power"); *see also* Martin Lythgoe, *Renewable Generation in Argentina: Past Failures and a Plan for Future Success*, 31 HOUS. J. INT'L L. 263, 336 (2009) (describing transmission problems in Argentina that hinder the development of renewable industries).

90. S. FINK ET AL., WIND ENERGY CURTAILMENT CASE STUDIES: MAY 2008 – MAY 2009 at 9 (2009), *available at* http://www.nrel.gov/docs/fy10osti/46716.pdf. Additionally, because only curtailments during the peak hours are counted, this does not account for total daily curtailments. *Id.*

wind-generated electricity is undelivered each day.[91] The cost of the undelivered wind energy is wrapped into the cost of service, raising the cost by 11%, or about $5/MWh at current rates.[92] For providers with take-or-pay provisions that require them to reimburse generators for unpaid PTCs, the cost of this undelivered energy raises the cost of service by about $7/MWh—slightly more than 16% of current rates.[93]

Within the next three years, 9.5 GW of new transmission capacity will be built to interconnect wind power, bringing total wind power transmission capacity in Texas to 18.5 GW.[94] ERCOT will integrate the transmission capacity to the existing grid through its Competitive Renewable Energy Zone (CREZ) program, which will alleviate congestion and ensure maximum deliverability of wind generation by sending wind power generated in west Texas to five zones throughout central and western Texas.[95] When compared with the current model, which sends all wind generation west to east along the same transmission line, the CREZ program will coordinate generated wind power with available capacity on multiple lines in order to better meet end-user demand.[96] Accordingly, if more wind power is generated than can be handled on one transmission line, the surplus generation is directed down another transmission line

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91. *Id.* "Although the percentage of wind that was curtailed in ERCOT varies considerably from day to day, [between December 2008 and July 2009,] it exceed[ed] 30% on over 20 occasions, over 40% on nine days, and over 50% one day." *Id.* at 10.

92. This calculation assumes current rates of about $50/MWh. *See generally* VISCUSI, VERNON & HARRINGTON, *supra* note 16, at 398–99 (noting that energy prices reflect the cost of providing service).

93. Remember that, for every MWh of energy curtailed, the provider pays the contract price plus the PTC—so, $40 + $21 = $61, or the price of 1.5 times as many MWh—as opposed to simply paying the contract price, where the federal government pays the PTC for every MWh delivered. *See supra* note 14 and accompanying text. Accordingly, if a generator is forced to curtail 10% of 100 MWh wind energy at $40/MWh with a PTC of $21/MWh, the provider must pay for 105 MWh, even though he will only take 90 MWh. The cost of the extra 15 MWh—$600—must be recovered as a surcharge to the 90 MWh delivered, raising their cost from $40/MWh to $47/MWh, more than a 16% increase.

94. S.B. 20, 2005 Leg., 79th Sess. (Tex. 2005); *see* Shiosansi & Hurlbut, *supra* note 84, at 3197 (discussing new transmission capacity in Texas).

95. PUCT, *supra* note 84, at 23–24.

96. *See id.* at 25 ("increased wind capacity tends to reduce the per-MWh price").

rather than being allowed to cause congestion and stranded costs.[97] If expanded transmission capacity means that no scheduled power is curtailed, the cost of service will be reduced by 11%[98] and, for providers with take-or-pay provisions that require payment of PTCs for each MWh of untaken output, the cost of service could be reduced by as much as $7/MWh.[99] As shown in Chart 7 below, these cost savings will translate to reduced costs for all wind generators.[100]

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[97]. *See id.* at 24.

[98]. *See* JOHANNES PFEIFENBERGER, PETER FOX-PENNER & DELPHINE HOU, TRANSMISSION INVESTMENT NEEDS AND COST ALLOCATION: NEW CHALLENGES AND MODELS 40 (2009), *available at* http://www.brattle.com/_documents/uploadlibrary/upload823.pdf (stating that loss-related capacity benefits added nearly 10% to production cost savings).

[99]. *See supra* note 93 and accompanying text; *see also* Shiosansi & Hurlbut, *supra* note 84, at 3196 (noting per customer rate impact of new transmission build-out); PUCT, *supra* note 84, at 66 (highlighting strong negative correlation between wind output and balancing energy rates at nearly 30%).

[100]. This is true even in light of the $4 per customer monthly surcharge to construct the new transmission lines. *See* Shiosansi & Hurlbut, *supra* note 84, at 3196.

Chart 7[101]

Comparative Cost of Providing Electricity
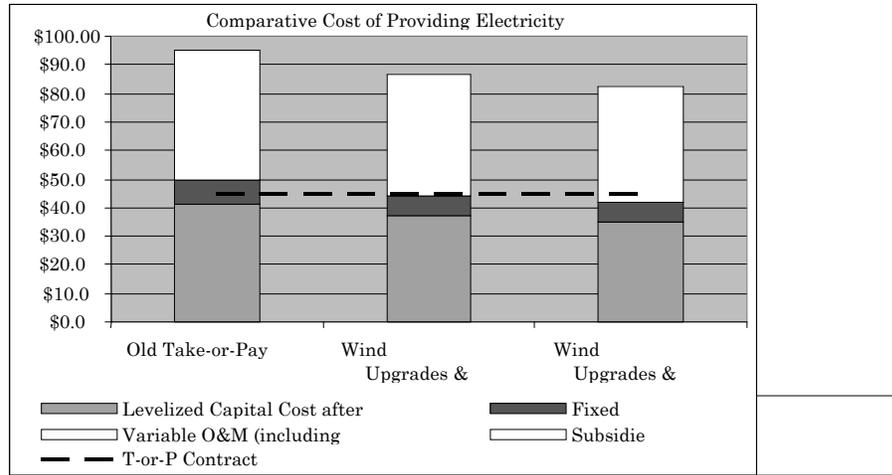
In a worst-case scenario that assumes perfect elasticity and two distinct retail providers—one with newly interconnected wind energy[102] and one with old fixed-cost take-or-pay wind energy—the competitive Texas retail electricity market will leave the take-or-pay provider with 97% of its generator's

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101. ANNUAL ENERGY OUTLOOK 2010, *supra* note 30; LEVINE, GRAVES & CELEBI, *supra* note 31, at 3; BLOSSMAN, FOLLOWILL & CHIPMAN, *supra* note 31, at 40; ALLIANCE BERNSTEIN, *supra* note 16, at 7. The chart incorporates the 11% cost reduction from delivering all scheduled energy, and also the amount of cost reduction to providers who are required to pay the PTC for energy generated but untaken. It also assumes a 2MW wind turbine cost of $2000/KW with a capacity of 35%, and wind energy subsidies of a 30% ITC, five-year accelerated depreciation with 50% of value captured, and $10/MWh REC. The subsidies detract from the levelized capital cost. *See supra* note 31 and accompanying text. It also assumes a long-term, take-or-pay contract rate of $45.00, recognizing that, in long-term, take-or-pay contracts, parties stick as close to average cost pricing as possible. *See* Johnston, Kavali & Neuhoff, *supra* note 20, at 2490.

102. By the end of 2011, new wind projects totaling 8 GW will be interconnected to the grid, bringing total wind generation in Texas to 16.5 GW. *See* BLOSSMAN, FOLLOWILL & CHIPMAN, *supra* note 31, at 15. An additional 42 GW of wind projects have been proposed. *Id.* "Proposed" means that companies have requested interconnection studies from ERCOT, which is the first step to construction. *Id.* In a best-case scenario, if half the proposed projects are completed by the end of 2013—interconnecting a total potential generation capacity of 37.5 GW—about 15 GW of capacity should be readily available and dispatchable along the CREZ transmission lines at any time of day. *Id.* at 20.

production at a cost it is unable to pass on to its retail customers, while the provider with newly interconnected wind power will find itself awash in new retail customers. As the take-or-pay provider is forced to pay 150% of the contract price per MWh for electricity it will never deliver, a breach of its WPPA may be the only way for it to avoid filing for Chapter 7 bankruptcy protection.

In a more realistic scenario,[103] the lower price of newly interconnected wind energy will combine with cost savings from other innovations, described below, to push the total cost of newly interconnected wind energy far below the long-term, fixed, take-or-pay costs associated with previously contracted-for wind energy.

B. *Improved Forecasting*

Wind generators' near-instant response to weather changes—and the concomitant change in electricity output—is one of the most challenging aspects of integrating wind energy to an efficient transmission grid.[104] Fortunately for ERCOT

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103. In the short term, customers are not that sensitive to changes in electricity prices, with an elasticity of around -0.4. ADRIAN CARTER ET AL., PRICE REFORM AND HOUSEHOLD DEMAND FOR ELECTRICITY 7–8, (2009), *available at* http://ccmfuwi.org/files/publications/conference/2009/papers/10_3-Carter_Craigwell_Moore-p.pdf. This insensitivity has been linked to the long-term, fixed contract basis of most demand. *Id.* at 6–7. Over the long term, however, prices become more elastic, hovering between -0.75 and -0.9. *Id.* Accordingly, in time, a high-cost provider will lose its customer base. *See* HUNG-PO CHAO, AN ECONOMIC FRAMEWORK OF DEMAND RESPONSE IN RESTRUCTURED ELECTRICITY MARKETS 38 (2008), *available at* http://www.hks.harvard.edu/hepg/Papers/2009/Demand%20Response%20in%20Restructured%20Markets%2002-08-09.pdf. However, calls for stochastic or real-time pricing, if accepted, would make the electricity market far more elastic in the short term. *See generally*, RAMTEEN SHIOSANSI, *Evaluating the Impacts of Real-Time Pricing on the Cost and Value of Wind Generation*, 25 IEEE TRANSACTIONS ON POWER SYS. 741 (2010) (introducing a demand response model that would allow electricity customers to respond to real-time price signals). But, as Chao shows, real-time demand response may increase the overall price of wind electricity because of arbitrage, the unsophisticated nature of many consumers, and other related factors. *See* CHAO, *supra* note 103, at 38.

104. *See* ALLIANCE BERNSTEIN, *supra* note 16, at 10. As an example, on February 26, 2008, a cold front moved through West Texas, drastically altering wind speed and causing wind generators to deliver 1,000 MW—82%—less than promised. ERCOT declared an emergency and began shutting down power to industrial customers, narrowly averting blackouts. *See* Gold, *supra* note 47.

planners, forecasting protocols have been implemented that accurately predict the amount of output from wind generators.[105] But these protocols forecast wind generation based on overly conservative estimates of wind potential, scheduling power the day ahead only if an 80% chance exists that the amount of power generated will exceed the amount of power scheduled, and interconnecting the power only if, in the hour before the energy is to be delivered, a 50% chance exists that the amount of power generated will exceed the amount of power scheduled.[106]

For providers, the overall cost impact of forecasting problems, including over- and under-estimations of wind generation, amounts to about $5 per MWh – just over 10% of current rates.[107] If these costs were eliminated, the divide between the price of newly interconnected wind energy and wind energy purchased under fixed price take-or-pay agreements would expand even further. Two developments on the near-term horizon aim to reduce these costs: new storage capacity and liberalized forecasting protocols.

1. New Storage Capacity

Compressed air energy storage (CAES) is currently being incorporated to Texas wind projects.[108] CAES "technology can increase utility reliance on intermittent renewable energy, eliminate wind power curtailment, enhance transmission

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105. These include sophisticated scheduling software applications that compile forecasts based on regional weather patterns, statistical models that analyze historical and real-time data, and telemetered real-time data provided by the wind generators themselves. *See* E. ELA & B. KIRBY, ERCOT EVENT ON FEBRUARY 26, 2008: LESSONS LEARNED 5–6 (2008), *available at* http://www.nrel.gov/docs/fy08osti/43373.pdf [hereinafter ERCOT EVENT ON FEBRUARY 26, 2008], at 5–6; *see also* Shiosansi & Hurlbut, *supra* note 84, at 3195.

106. ERCOT Protocols §§ 4.4.15, 4.5.12; *see* ERCOT EVENT ON FEBRUARY 26, 2008, *supra* note 104, at 6–7. *See also* Shiosansi & Hurlbut, *supra* note 84, at 3195.

107. PAUL DENHOLM ET AL., THE ROLE OF ENERGY STORAGE WITH RENEWABLE ELECTRICITY GENERATION 21 (2010), *available at* http://www.nrel.gov/docs/fy10osti/47187.pdf.

108. *See* Richard A. Kessler, *General Compression in Storage Deal with ConocoPhillips*, RECHARGE, Apr. 15, 2010, *available at* http://www.rechargenews.com/business_area/innovation/article211931.ece.

utilization, and make dispatchable wind . . . power available to customers."[109] A recent study found that, although CAES would add about 50% to a wind project's capital costs and a variable cost of about \$12/MWh for fuel, it would expand a generator's average capacity to 85% from about 40%—reducing overall costs by about \$13/MWh, almost 30% at current rates.[110] Because CAES would enable sufficient energy storage to accurately schedule wind power, it would change the characterization of wind generators from intermittent to firm service providers.[111] Stored wind energy would allow generators and providers to levelize output and scheduling, delivering a consistent amount of electricity to the grid.[112] Accordingly, this \$13 reduction eliminates the \$5/MWh loss caused by forecasting errors.[113]

However, in a world with cap-and-trade laws,[114] CAES, which runs off natural gas and creates about 0.2 tons of CO_2 per MWh generated,[115] would incur costs of about \$6/MWh at a CO_2 price of \$30.[116] The net benefit in that situation would be total cost savings of about \$7/MWh, nearly 15% of costs at current rates.[117] As shown in Chart 8 below, the reduced costs are significant with or without the CO_2 price.

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109. *Id.*

110. *See* Samir Succar & Robert Williams, *Wind Coupled to Compressed Air Energy Storage (CAES) for Baseload Power Generation: An Integrated Optimization of Wind with Storage* (Feb 2009) (unpublished A.B. thesis, Princeton University), *available at* http://www.princeton.edu/pei/energy/presentations/Succar_Eurosolar_Poster.pdf. Other researchers have come to similar conclusions. *See, e.g.*, ROY DANIEL, COMPRESSED AIR ENERGY STORAGE: A MISSING PIECE OF THE PUZZLE FOR A GREEN, AFFORDABLE AND RELIABLE ELECTRIC GRID FOR THE 21ST CENTURY 14–21 (2009), *available at* http://www.cera.com/aspx/cda/filedisplay/filedisplay.ashx?PK=35893.

111. *See* DANIEL, *supra* note 110, at 7–8.
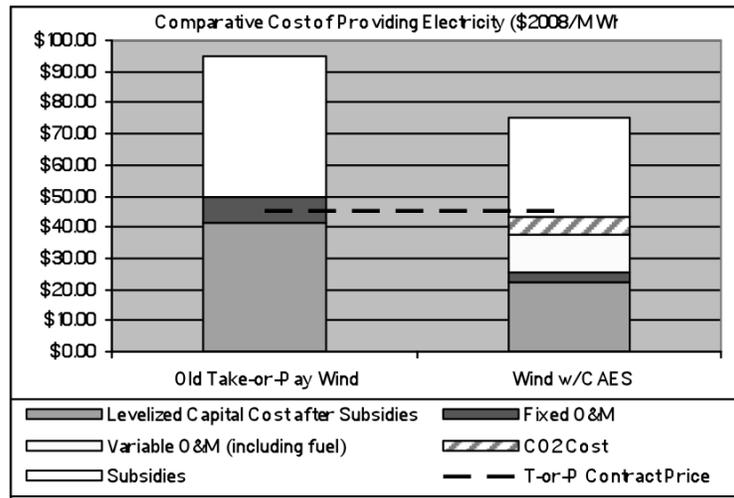
112. *Id.*

113. *See id.*

114. *But see supra* note 75 and accompanying text.

115. *See* DANIEL, *supra* note 110, at 11.

116. *See supra* notes 69–74 and accompanying text and chart.

117. This calculation assumes current rates of about \$50/MWh. *See supra* note 93 and accompanying text.

Chart 8[118]

Comparative Cost of Providing Electricity ($2008/MWt

2. *Liberalized Forecasting Protocols*

Current ERCOT protocols allow for wind energy to be scheduled for transmission only if there is an 80% chance of exceedance.[119] In some studies, the output loss due to the 80% exceedance rule—as opposed to a 50% exceedance rule—has been more than 10%.[120] Although excess generation can be sold

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118. ANNUAL ENERGY OUTLOOK 2010, *supra* note 30; LEVINE, GRAVES & CELEBI, *supra* note 31, at 3; BLOSSMAN, FOLLOWILL & CHIPMAN, *supra* note 31, at 40; ALLIANCE BERNSTEIN, *supra* note 16, at 7. The chart incorporates the 11% cost reduction from delivering all scheduled energy, and also the amount of cost reduction to providers who are required to pay the PTC for energy generated but untaken. It also assumes a 2MW wind turbine cost of $2000/KW with a capacity of 35%, and wind energy subsidies of a 30% ITC, five-year accelerated depreciation with 50% of value captured, and $10/MWh REC. The subsidies detract from the levelized capital cost. *See supra* note 31 and accompanying text. It also assumes a long-term, take-or-pay contract rate of $45.00, recognizing that, in long-term, take-or-pay contracts, parties stick as close to average cost pricing as possible. *See* Johnston, Kavali & Neuhoff, *supra* note 20, at 2490.

119. ERCOT Protocols §§ 4.4.15, 4.5; ERCOT EVENT ON FEBRUARY 26, 2008, *supra* note 104, at 6–7; Shiosansi & Hurlbut, *supra* note 84, at 3195.

120. AGNES FONTAINE & PETER ARMSTRONG, UNCERTAINTY ANALYSIS IN ENERGY YIELD ASSESSMENT 9 (2007), *available at* http://www.ewec2007proceedings.info/ allfiles2/497_Ewec2007fullpaper.pdf (examining results from an 863 kW wind farm in Italy comprising twenty-seven wind turbines with a 26% capacity factor; at 80%

on the spot market,[121] no guarantee exists that buyers will demand wind energy in the spot market.

Market participants in ERCOT have recently introduced Protocol Revision Requests (PRR) that would lower the scheduling exceedance level from 80% to 50%.[122] They claim that introduction of the AWS Truewind forecasting software application has improved forecasting to the point that a 50% exceedance level is sufficient to align generation with scheduled quantities.[123] If ERCOT accepts the PRRs, wind generators without CAES storage facilities can expect cost savings of about 11%, or about $5/MWh at current rates.[124] Wind generators with CAES can still likely expect some cost savings, although the stored electricity capabilities will have already significantly reduced—if not eliminated—the amount of undelivered output.[125] Accordingly, as shown in Chart 9 below, a 50% exceedance limit for scheduling under ERCOT's Nodal Protocols would result in cost savings of about $5/MWh, almost delivering

exceedance, the wind farm produced 45.82 GWh/y, while at 50% exceedance, the wind farm produced 51.53 GWh/y). That said, the unpredictable nature of wind can surprise even the most cautious estimates. *See* Gold, *supra* note 47 (reporting a recent event where a sudden drop-off in wind meant that 160 MW less power was being delivered than was scheduled).

121. Anthony Papavasilou & Shmuel S. Oren, Integration of Contracted Renewable Energy and Spot Market Supply to Serve Flexible Loads 1–2, (unpublished manuscript) *available at* http://www2.decf.berkeley.edu/~tonypap/CouplingV2.pdf (last visited Nov. 21, 2010).

122. *See, e.g.*, Revise Total ERCOT Wind Power Forecast *(*TEWPF*)*, PRR No. 841 (Nov. 30, 2009) (proposing amendments to Nodal Protocol §§ 2.1, 2.2, 4.4.15, 4.5.12).
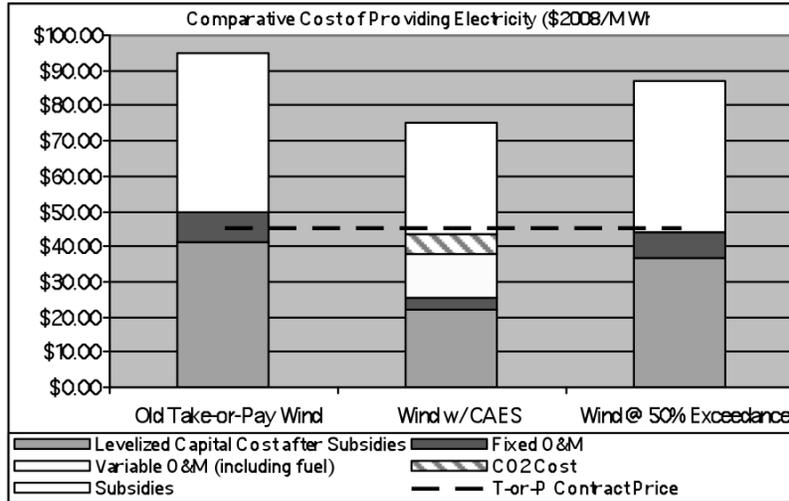
123. *Id.* AWS Truewind provides advanced atmospheric modeling and measurement services to forecast wind and weather patterns for wind projects and regulatory bodies charged with scheduling wind power on transmission lines. *See New US Wind Potential Estimates*, AWS TRUEPOWER (Feb. 19, 2010), http://www.awstruepower.com/2010/02/new-us-wind-potential-estimates/. The DOE's Wind Energy Program relies on AWS Truewind's data, believing it to be the most accurate forecasting software. *Id.*

124. *See* FONTAINE & ARMSTRONG, *supra* note 120, at 9 (concluding that 10% of generation output is lost at 80% exceedance, as opposed to 50% exceedance, resulting in cost savings per MWh of about 11%); *see also* DENHOLM ET AL., *supra* note 107, at 21 (noting that improved forecasting would result in cost savings of 12%, or about $5/MWh at current rates).

125. *See* DANIEL, *supra* note 110, at 8.

the same value to wind generators that they would receive from CAES storage capabilities.

Chart 9[126]

Comparative Cost of Providing Electricity ($2008/MWh)

Legend: Levelized Capital Cost after Subsidies; Fixed O&M; Variable O&M (including fuel); CO2 Cost; Subsidies; T-or-P Contract Price

3. Impact of Technology on Cost Assumptions

As discussed, wind power has the lowest marginal cost—because void of variable costs—among predominant generator sources in Texas. As output capacity increases, therefore, its average cost decreases; for every additional MWh generated, the fixed costs per MWh are spread out and, accordingly, reduced.[127]

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126. ANNUAL ENERGY OUTLOOK 2010, *supra* note 30, at 67; LEVINE, GRAVES & CELEBI, *supra* note 31, at 3; BLOSSMAN, FOLLOWILL & CHIPMAN, *supra* note 31, at 40; ALLIANCE BERNSTEIN, *supra* note 16, at 7. The chart incorporates the $13/MWh savings from CAES, and assumes a CAES-extended capacity of 85%, with a $30/ton CO_2 price. It also incorporates the 11% price reduction from liberalized forecasting protocols. It assumes Henry Hub prices of $5/MMbtu, and a 2MW wind turbine cost of $2000/KW with a capacity of 35%, and wind energy subsidies of a 30% ITC, five-year accelerated depreciation with 50% of value captured, and $10/MWh REC. The subsidies detract from the levelized capital cost. It also assumes a long-term, take-or-pay contract rate of $45.00, recognizing that, in long-term, take-or-pay contracts, parties stick as close to average cost pricing as possible. *See* Johnston, Kavali & Neuhoff, *supra* note 20, at 2490.

127. *See* VISCUSI, VERNON & HARRINGTON, *supra* note 16, at 358–71 (discussing average cost pricing of electric utilities).

When new transmission capacity is added to the grid, reducing curtailments and more efficiently aligning supply with demand, previously lost output equal to 10% becomes available on the grid.[128] When liberalized forecasting protocols are introduced, generators will be able to increase scheduled output by another 10%.[129] And if the rotors on a turbine are replaced with new rotors 9% larger, output could be increased an additional 17%.[130] Finally, generators who utilize CAES technology can increase output by as much as 250%.[131] Altogether, then, new technologies and regulations will lead to output increases between 20% and 40% for each generator—bringing 35% capacity generators above 45% capacity, and bringing 40% capacity generators close to 55% capacity, as shown in Table 1 below—leading to cost reductions of between 20% and 30%.[132]

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128. *See supra* notes 94–99 and accompanying text.

129. *Id.*

130. *See generally* U.S. DEP'T OF ENERGY, 20% WIND ENERGY BY 2030: INCREASING WIND ENERGY'S CONTRIBUTION TO U.S. ELECTRICITY SUPPLY 57 (2008), *available at* https://www1.eere.energy.gov/windandhydro/pdfs/41869.pdf (discussing how wind capacity can be increased by enlarging and installing larger rotors).

131. *See supra* notes 109–27 and accompanying text.

132. The DOE predicts that wind turbines will operate between 40% and 50% capacity once new technologies and transmission upgrades are implemented. *See* U.S. DEP'T OF ENERGY, *supra* note 130, at 61.

Table 1[133]

Costs								
Capacity	35%	40%	45%	50%	55%	60%	65%	70%
Cost/ KWh	$0.09	$0.08	$0.07	$0.06	$0.06	$0.05	$0.05	$0.04
Fixed O&M Cost/ KW	25	25	25	25	25	25	25	25
Fixed O&M Cost/ KWh	$0.01	$0.01	$0.01	$0.01	$0.01	$0.00	$0.00	$0.00
Total Cost/ MWh	$95.13	$83.24	$73.99	$66.59	$60.54	$55.49	$51.22	$47.56
Subsidies								
30% ITC/ Cash Grant	$26.09	$22.83	$20.29	$18.26	$16.60	$15.22	$14.05	$13.05
PTC	$21.00	$21.00	$21.00	$21.00	$21.00	$21.00	$21.00	$21.00
MACRS	$9.51	$8.32	$7.40	$6.66	$6.05	$5.55	$5.12	$4.76
REC	$10.00	$10.00	$10.00	$10.00	$10.00	$10.00	$10.00	$10.00
Total Cost Per MWh								
With ITC/ Cash Grant	**$49.52**	**$42.08**	**$36.30**	**$31.67**	**$27.88**	**$24.72**	**$22.05**	**$19.76**
With PTC	**$54.62**	**$43.91**	**$35.59**	**$28.93**	**$23.48**	**$18.94**	**$15.10**	**$11.81**

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133. ANNUAL ENERGY OUTLOOK 2010, *supra* note 30. This table assumes a 2MW wind turbine cost of $2000/KW, and fixed O&M costs of $15 per MWh and $20,000 per turbine per year; and it assumes wind energy subsidies of a 30% ITC, five-year accelerated depreciation with 50% of value captured, and $10/MWh REC. The subsidies detract from the levelized capital cost. *See supra* note 30 and accompanying text. For every increase in capacity, the number of MWh generated increases, decreasing the average cost of creating additional units of wind energy.

Predicting one's ability to maximize output capacity is especially important at the planning phase, when a generator is determining whether to take the PTC, ITC, or cash grant.[134] Once the generator chooses a tax crediting mechanism, it is stuck with its decision.[135] For projects operating at less than 30% capacity, the ITC or cash grant provide more value.[136] But for projects plugged into improved transmission lines, applying better forecasting models, and/or utilizing CAES storage, the $21/MWh PTC likely provides more long-term value.[137] As Chart 10 below shows, the PTC delivers as much as 10% in additional cost savings for projects enjoying capacity of 50% or better.[138] In a best case scenario, then, the total impact of these changes could reduce wind energy's rate per MWh by as much as 40%, making it the cheapest energy source in ERCOT.[139]

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134. *See supra* note 30 and accompanying text.

135. *See* American Recovery and Reinvestment Act of 2009, Pub L. 111-5, § 1110, 123 Stat. 115, 516; *see also* BOLINGER ET AL., *supra* note 42, at 1–2 (discussing the advantages and disadvantages of choosing one or the other).

136. *See* BOLINGER ET AL., *supra* note 42, at 6.

137. *Id.*

138. However, if one has take-or-pay provisions in one's PPA, one should also consider the cost of overestimating output and the threat of a requirement that the provider pay the PTC for every MWh of energy generated but undelivered. *See supra* note 42 and accompanying text. With assumptions similar to those modeled above, the ITC or cash grant–especially in light of the up-front value of the cash grant–likely provides the most value for any wind project with capacity below 50%.

139. *See infra* note 153 and accompanying chart.

Chart 10[140]
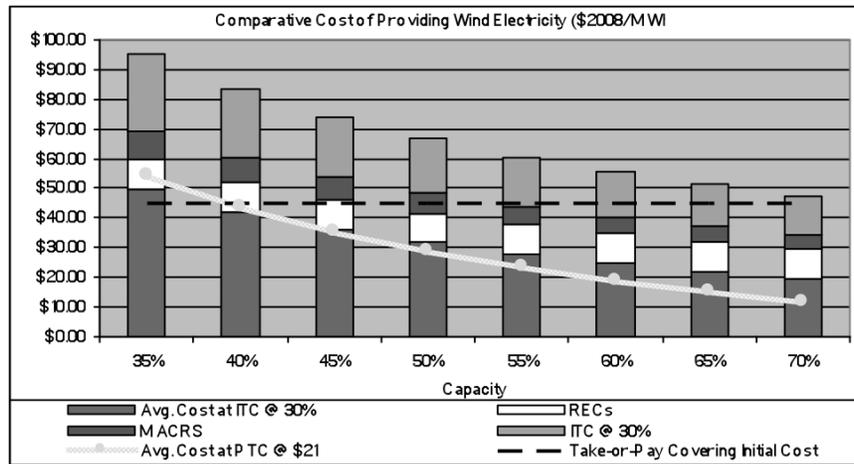
4. Comparative Cost of Replacement Fuels

Where wind generation offsets gas generation on a near MWh-to-MWh basis,[141] falling gas prices foretell hardship for providers of fixed-cost, take-or-pay wind power.[142] Unfortunately for providers, recent developments in the gas industry have the potential to drive down prices further.[143] The

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140. ANNUAL ENERGY OUTLOOK 2010, *supra* note 30; LEVINE, GRAVES & CELEBI, *supra* note 31, at 3; BLOSSMAN, FOLLOWILL & CHIPMAN, *supra* note 31, at 40; ALLIANCE BERNSTEIN, *supra* note 16, at 7. This table assumes a 2MW wind turbine cost of $2000/KW, and fixed O&M costs of $15 per MWh and $20,000 per turbine per year; and it assumes wind energy subsidies of a 30% ITC, five-year accelerated depreciation with 50% of value captured, and $10/MWh REC. The subsidies detract from the levelized capital cost. *See supra* note 30 and accompanying text. For every increase in capacity, the number of MWh generated increases, decreasing the average cost of creating additional units of wind energy.

141. *See* Gold, *supra* note 48 (noting that, since 2007, wind-generated power has increased from 2% to 6% of the Texas market, while gas-generated power has decreased from 46% to 42% of the Texas market).

142. Until 2009, average gas prices hovered between $5/MMbtu and $8/MMbtu. *EIA Natural Gas Summary*, *supra* note 63. In April 2010, Henry Hub prices hit $3.80/MMbtu with no signs of stopping their downward descent. *See supra* note 63.

143. The most notable of these developments are the increased production from shale reserves and the construction of a gas pipeline in Alaska to bring supplies down from the North Slope. ENERGY INFO. ADMIN., PRESENTATION: ANNUAL ENERGY OUTLOOK

Department of Energy (DOE) predicts that gas produced from shale and Alaska reserves alone will supply close to 30% of domestic needs by 2025—up from about 5% in 2010.[144] Where U.S. demand is fairly constant, this increase in domestic supply will offset both imports and higher-priced domestic supplies.[145]

As show in Chart 11 below, if the Henry Hub spot price drops to $3/MMbtu,[146] the cost of gas-generated power will be nearly 20% less expensive than that of subsidized wind power.[147] In a competitive, price-responsive market, customers will shift their demand from wind power to cheaper gas power.[148] For all providers with take-or-pay provisions, the drop in demand will mean that they will have to continue paying for every MWh of wind energy generated, regardless of whether customers are willing to pay for it. For providers with take-or-pay provisions that require them to also pay the PTC for each MWh not taken, the drop in demand will mean that they have to pay 150% of the contract price—200% of the market price for gas-generated energy[149]—for every MWh of energy generated. Without flexibility to respond to the volatility of natural gas prices, a reduction in gas prices could spell providers' early demise.

2010: REFERENCE CASE 17 (Dec. 14, 2009), *available at* http://www.eia.doe.gov/neic/speeches/newell121409.pdf [hereinafter EIA PRESENTATION]. President Obama's initiative to open up areas along U.S. coasts for exploration and development also promises to increase domestic supply. *See* John M. Broder, *Obama to Open Offshore Areas to Oil Drilling for First Time*, N.Y. TIMES, Mar. 31, 2010, at A1.

144. *See* EIA PRESENTATION, *supra* note 144, at 17.

145. *Id.*

146. *See supra* note 63 (predicting decline past $3.80/MMbtu).

147. *See supra* note 62 and accompanying text.

148. In switching, customers would reverse their trend of the last several years, when wind power offered the cheaper alternative. *See* Gold, *supra* note 48 (noting that, since 2007, wind-generated power has increased from 2% to 6% of the Texas market, while gas-generated power has decreased from 46% to 42% of the Texas market).

149. If the contract price is $40 and the PTC is $21, providers with take-or-pay provisions will pay $61. If the Henry Hub price is $3/MMbtu and gas-generated power is selling for $30/MWh, then take-or-pay wind power is twice as expensive and, hence, unlikely to sell. *See supra* notes 59–66 and accompanying text.

Chart 11[150]
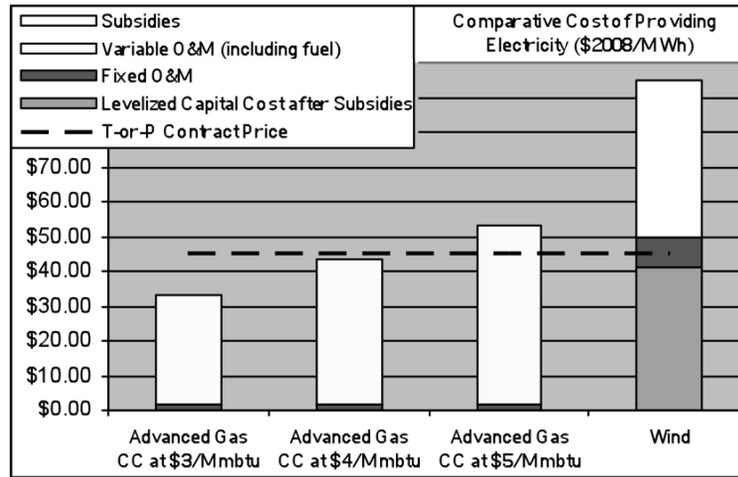
V. THE PERFECT STORM

In a likely scenario involving new transmission and liberalized forecasting protocols, wind generators may be able to increase their average capacity to 55%. The cost of wind-generated power will then be reduced by 40% or more, as compared to that generated under fixed-cost, take-or-pay contracts.[151] As shown in Chart 12 below, the 40% plus in cost reductions contributes to an average cost for all wind generators (not already restricted by onerous take-or-pay provisions) that beats the market price for energy.[152]

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150. ANNUAL ENERGY OUTLOOK 2010, *supra* note 30; LEVINE, GRAVES & CELEBI, *supra* note 31, at 3; BLOSSMAN, FOLLOWILL & CHIPMAN, *supra* note 31, at 40; ALLIANCE BERNSTEIN, *supra* note 16, at 7. The chart assumes Henry Hub gas prices of $5/MMbtu, and a 2MW wind turbine cost of $2000/KW with a capacity of 35%, and wind energy subsidies of a 30% ITC, five-year accelerated depreciation with 50% of value captured, and $10/MWh REC. The subsidies detract from the levelized capital cost. *See supra* note 30 and accompanying text. It also assumes a long-term, take-or-pay contract rate of $45.00, recognizing that, in long-term, take-or-pay contracts, parties stick as close to average cost pricing as possible. *See* Johnston, Kavali & Neuhoff, *supra* note 20, at 2490.

151. *See supra* note 139 and accompanying text.

152. *See supra* notes 126–31 and accompanying text.

Chart 12[153]
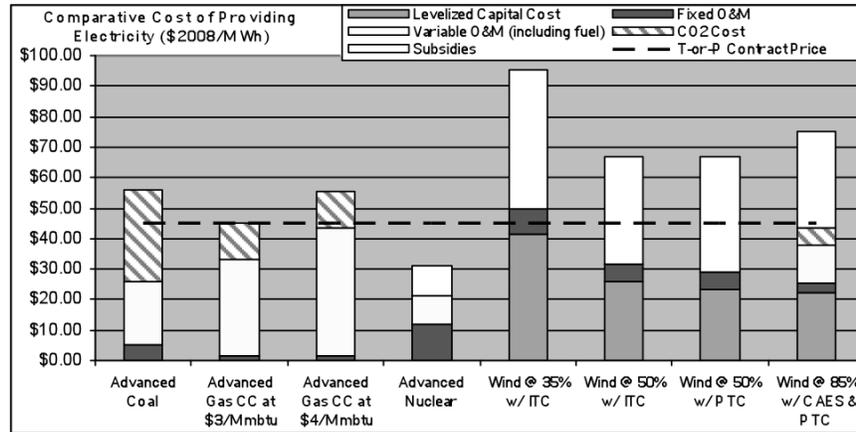
As you can see in Chart 12, without cap-and-trade, fixed-cost, take-or-pay wind energy is barely competitive with cost-recovered, gas-generated energy while gas is at $4/MMBtu, and is not competitive at all with cost-recovered, coal or nuclear-generated energy, or with cost-recovered, gas-generated energy when gas hits $3/MMBtu. But as new WPPAs are made, providers will be able to take into account output capacity increases from improved transmission and technology, and from new forecasting protocols, securing wind power at prices more than 30% below that of fixed-cost take-or-pay wind power;[154] then, wind is competitive even with fully cost-recovered nuclear plants.[155] The cheap price of new wind energy will send price

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153. ANNUAL ENERGY OUTLOOK 2010, *supra* note 30; LEVINE, GRAVES & CELEBI, *supra* note 31, at 3; BLOSSMAN, FOLLOWILL & CHIPMAN, *supra* note 31, at 40; ALLIANCE BERNSTEIN, *supra* note 16, at 7. The chart assumes Henry Hub gas prices of $5/MMbtu unless otherwise noted, coal prices of $1/MMbtu, uranium prices of $41/lb of U_3O_8, a $30/ton CO_2 price, a 2MW wind turbine cost of $2000/KW, and wind energy subsidies of a $21/MWh PTC, a 30% ITC, five-year accelerated depreciation with 50% of value captured, and $10/MWh REC. The subsidies detract from the levelized capital cost. *See supra* note 30 and accompanying text. It also assumes a long-term take-or-pay contract rate of $45, recognizing that, in long-term, take-or-pay contracts, parties stick as close to average cost pricing as possible. *See* Johnston, Kavali & Neuhoff, *supra* note 20, at 2490.

154. *See supra* note 153 and accompanying chart.

155. *See supra* note 153 and accompanying chart.

signals through the market and will kill demand for the more expensive take-or-pay wind energy, leaving those providers with huge amounts of energy that they cannot deliver—and for which they may have to pay the $21/MWh PTC. At some point, these providers may choose, like their gas pipeline forebears a generation earlier, that it is more economical to breach the WPPAs and risk suit by generators than it is to continue paying and remain unable to off-take any output.

A. Protection for Clients

The probability is very low that wind projects will find investment unless take-or-pay provisions guarantee investors full cost-recovery. However, the potential for fixed-cost, take-or-pay provisions to price wind power out of the market should give these same investors pause. How beneficial is an up-front guaranteed return on investment when providers decide to breach their WPPAs and sign up cheaper wind power, or else file for bankruptcy protection?

As discussed above, technological and regulatory improvements to ERCOT's system will positively affect all generators, regardless of when their turbines came online.[156] New transmission capacity will reduce or eliminate curtailments, adding 10% to every generator's deliverable output.[157] Revised Nodal forecasting protocols will add an additional 10% to every generator's deliverable output, as generators will be allowed to schedule more generation.[158] And new technologies will lead to improvements in turbine output generation of between 10% and 20%.[159] These output capacity increases will reduce generators' average costs. As shown in Chart 13 below, generators operating under fixed-cost, take-or-pay contracts will enjoy substantial profits as their output capacity increases, while providers will experience substantial losses.
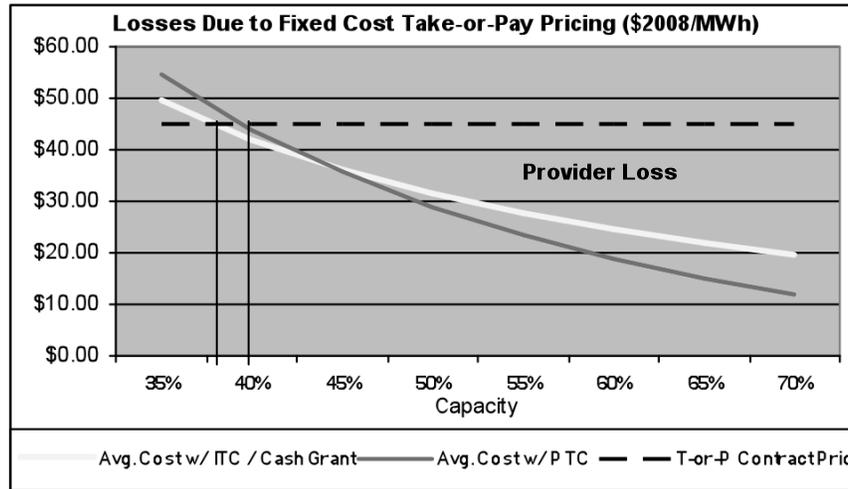
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156.   *See supra* notes 125–39 and accompanying text and charts.

157.   *See supra* notes 127–32 and accompanying text.

158.   *Id.*

159.   *See supra* note 132 and accompanying text.

Chart 13[160]

Losses Due to Fixed Cost Take-or-Pay Pricing ($2008/MWh)

Accordingly, these generators have a huge incentive to encourage technological and regulatory leaps in generating and transmitting wind power, putting them at odds with providers who signed long-term, fixed-cost, take-or-pay contracts—at least in the beginning. While this may provide benefits to the industry, it will also price wind generation out of the market. Providers will be locked into long-term, fixed-cost, take-or-pay contracts. Unless all parties take into account the potential for increases to output capacity and their concomitant cost-reductions, providers who want to stay competitive may need to breach their contracts and find new generation at more reasonable terms.

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160. ANNUAL ENERGY OUTLOOK 2010, *supra* note 30; LEVINE, GRAVES & CELEBI, *supra* note 31, at 3; BLOSSMAN, FOLLOWILL & CHIPMAN, *supra* note 31, at 40; ALLIANCE BERNSTEIN, *supra* note 16, at 7. This table assumes a 2MW wind turbine cost of $2000/KW, and fixed O&M costs of $15/MWh and $20,000 per turbine per year; and it assumes wind energy subsidies of a 30% ITC, five-year accelerated depreciation with 50% of value captured, and $10/MWh REC. The subsidies detract from the levelized capital cost. *See supra* note 30 and accompanying text. For every increase in capacity, the number of MWh generated increases, decreasing the average cost of creating additional units of wind energy.

B. Contract Negotiations

For new WPPAs, generators and providers should design flexible take-or-pay provisions that account for system impacts, allowing for periodic adjustments to the contract rate.[161] For instance, a provision could allow for renegotiation of the contract price every year could guarantee a levelized profit percentage each year; or it could set up a sliding scale of output capacity benchmarks at which the contract rate per MWh will shift downward.

Although the characteristics of a "perfect" model are too difficult and location-specific to model here, all interested parties should acknowledge that take-or-pay provisions must account for systemic changes. As documented above, capital costs make up the largest share of costs recovered in each MWh of wind energy.[162] Take-or-pay provisions that lock in these costs become onerous when external factors affect assumptions in the rate model, spreading out the cost recovery across a larger number of MWh of energy and making other similarly situated wind generators' energy less expensive. This locked-in rate is similar to the gas take-or-pay contracts in the 1980s, which locked in the cost of gas at a high rate per MMbtu.[163] When gas prices dropped, the take-or-pay provisions became burdensome because they required gas marketers to pay the contract price for each MMbtu of gas they purchased, even though they could buy the same gas for a much cheaper price from a similarly situated producer.[164]

In the end, flexible take-or-pay provisions could be good for both providers and generators: providers will be able to offer their customers a competitive rate, and will likely pick up new customers and sell more electricity as prices continue to drop; and generators will be insured a return on their investment.

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161. *See* Johnston, Kavali & Neuhoff, *supra* note 20, at 2481. Long-term take-or-pay contracts try to hew close to project costs. *Id.*

162. *See supra* notes 29–36 and accompanying text and charts.

163. *See supra* notes 1–6 and accompanying text.

164. *See supra* notes 3–8 and accompanying text.

C. Pre-Litigation

If a controlling WPPA contains a fixed-cost, take-or-pay provision, providers and generators are both well served by renegotiating the terms of the provision. For the reasons stated in the section immediately above, a flexible and/or adjustable take-or-pay provision that accounts for systemic effects on wind power's cost per MWh will ensure competitiveness and continued profitability for all parties. A renegotiated flexible rate that carries a settlement surcharge for partial take-or-pay amounts would at least allow the contract rate to follow market prices for energy.

D. Litigation

But if generators will not renegotiate their take-or-pay provisions—and after system effects reduce the cost of providing wind energy by 20% or more—providers may be well-advised to breach their PPAs and wait for generators to try and sue them. But providers should take heed, here, because the difference between gas and wind energy is important: when wind energy is not taken, wind generators not only lose revenue but they also have to increase their cost recovery in subsequent MWhs to make up for the undelivered energy. Because the average cost of wind energy is dictated entirely by the amount of fixed costs recovered in each MWh, the fewer the MWhs delivered, the higher the cost per MWh delivered. If providers stop taking a wind generator's energy and the generator is restrained by market forces from increasing the price of its additional generation, its lost revenue will likely comprise any damage award. The damage award would then be passed on to customers, raising the rate. So, regardless of how the rate increases, if providers stop taking a wind generator's energy, the increased rate will likely impact the competitiveness of wind energy versus energy generated by other fuel sources, potentially pricing wind energy out of the market all over again. Then, everyone loses.

If a generator refuses to renegotiate its take-or-pay agreement, it may be in a provider's best interest to anticipatorily breach its contract before the generator's costs are reduced too much. The provider should immediately re-contract

with the generator to take its electricity at market rates or at a new, flexible take-or-pay rate. Whatever the provider does, it must immediately cover the generator's losses. If the generator refuses to deliver energy to the provider, the generator will lose 100% of the value of that generation—and it will deliver a fantastic defense to the provider in a later suit, perhaps precluding any award. But as long as the generator continues supplying energy, it will be free to sue for prior take-or-pay amounts while ensuring that it recovers at least the market rate. Then, if the generator wins its lawsuit in full, the damages amount could be added to the cost of service and collected over time – increasing costs back to the take-or-pay-level. Then again, a full judgment would likely price wind out of the market. However, it is more likely that, as with the gas take-or-pay crisis, the wind generator will receive market value for every MWh generated and the generator will get a partial judgment for pennies on the dollar. Those costs, while added to the cost of service, will not raise it enough to make wind power uncompetitive with alternative fuel-fired generators. Providers will be able to continue meeting customer demand, and generators will continue receiving more than the market price for wind energy. Then, everyone wins.