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**Via HAND DELIVERY**

Cynthia T. Brown, Chief
Section of Administration
Office of Proceedings
Surface Transportation Board
395 E Street, SW
Washington, D.C. 20423

Re: STB Ex Parte No. 717, Petition of the Association of American Railroads to Institute a Rulemaking Proceeding to Reintroduce Indirect Competition as a Factor Considered in Market Dominance Determinations for Coal Transported to Utility Generation Facilities

Dear Ms. Brown,

Enclosed for filing in STB Ex Parte No. 717, please find the original and ten copies of: (1) the Petition of the Association of American Railroads to Institute a Rulemaking Proceeding to Reintroduce Indirect Competition as a Factor Considered in Market Dominance Determinations for Coal Transported to Utility Generation Facilities, (2) the Verified Statement of David A, Reishus in support of the Petition, and (3) an additional set of all figures presented in the Petition and Verified Statement.

In addition to the paper copies, we are submitting three CDs containing electronic versions of the set of documents described above. Please note there are color figures in all three documents, and those figures are presented in color in all the electronic and hard copies provided with this filing.

Please date stamp the extra copies of this cover letter and the enclosed pleading and return them to our messenger. Thank you for your attention to this matter.

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Respectfully submitted,

Jeffrey A. Streeter
*Counsel for the Association of American Railroads*

Enclosures

BEFORE THE
SURFACE TRANSPORTATION BOARD 233372

STB Ex Parte No. 717

**PETITION OF THE ASSOCIATION OF AMERICAN RAILROADS TO INSTITUTE A RULEMAKING PROCEEDING TO REINTRODUCE INDIRECT COMPETITION AS A FACTOR CONSIDERED IN MARKET DOMINANCE DETERMINATIONS FOR COAL TRANSPORTED TO UTILITY GENERATION FACILITIES**



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**November 19, 2012**

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**BEFORE THE**
**SURFACE TRANSPORTATION BOARD**

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# PETITION OF THE ASSOCIATION OF AMERICAN RAILROADS TO INSTITUTE A RULEMAKING PROCEEDING TO REINTRODUCE INDIRECT COMPETITION AS A FACTOR CONSIDERED IN MARKET DOMINANCE DETERMINATIONS FOR COAL TRANSPORTED TO UTILITY GENERATION FACILITIES

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Pursuant to 49 C.F.R. § 1110.2(b), the Association of American Railroads ("AAR") hereby requests that the Surface Transportation Board ("Board") initiate a rulemaking proceeding and propose the reintroduction of product and geographic competition as factors that may be considered in market dominance analyses under 49 U.S.C. § 10707 for complaints involving the transportation of coal to coal-fired electric generation facilities. The limiting effect of such indirect competition—particularly the often head-to-head competition between natural gas and coal as fuel for wholesale power generation—is so profound today, and for the foreseeable future, that it simply is too important a factor to ignore in the market dominance analysis. And in contrast to the situation more than a decade ago, when this Board concluded that analysis of indirect competition had proven too burdensome and time consuming, developments in the wholesale electric power and natural gas markets and in public access to readily available data now make it relatively simple and inexpensive to identify the limiting effect of indirect competition exercised in the wholesale power markets on coal transportation rates in those circumstances where it exists—and to identify as well those circumstances where it does not.[1] To be explicit, this Petition asks the Board to allow for the introduction and

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[1] The term "indirect competition" as generally understood and as used throughout this Petition encompasses both product and geographic competition. See further discussion of direct and indirect competition *infra* pp. 6-7. While this Petition focuses primarily on product competition

consideration of evidence of product and geographic competition in *coal rate cases only, and does not contend that coal transportation rates for every coal-fired generation facility are effectively limited by indirect competition exerted in the wholesale power markets.*

## INTRODUCTION

Dramatic changes in the wholesale power and natural gas markets compel reconsideration of the Board's 1998 decision to exclude consideration of indirect competition for two reasons. First, revolutionary changes in the domestic supply market for natural gas have pushed the price of natural gas to historic lows relative to coal, allowing natural gas-fired electric generation to displace significant amounts of coal-fired generation in many wholesale power markets. Although some coal-fired generation resources have remained more competitive than other generation resources and continue to operate at their historical output levels, others that once ran continuously, regardless of whether the delivered price of coal rose or fell, now run much less frequently, and sometimes rarely if at all, because of increased head-to-head competition from other generation resources, especially natural gas-fired generation. Such competition is constraining railroad pricing for transportation of coal to certain coal-fired generation facilities. Under these circumstances a railroad cannot have market dominance and there is no basis for the Board to exercise rate reasonableness jurisdiction.

Second, simple, transparent and conservative methods for identifying direct competition exercised in the newly formed wholesale power markets now provide the Board and the parties to a potential rate dispute with something they lacked in 1998: a practical and easily compiled body of evidence for analyzing whether indirect competition exists and the effect of this indirect

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between coal and natural gas-fired generation in wholesale power markets, both product and geographic competition can constrain rates for the transportation of coal to coal-fired generation facilities, and the simple, transparent approaches described in this Petition can identify and measure both effects together.

competition on a challenged rail carrier's transportation of coal to a given generation facility.

For example, as described in greater detail below:

- Publicly available historic generation data can now be analyzed to demonstrate where power generated by a given coal-fired generation facility has been displaced by power generated at alternative generation resources in response to relatively small changes in their respective marginal costs, indicating that rail transportation of coal to that generation facility is subject to effective indirect competition.

- Alternatively, readily generated wholesale power supply curves indicating the available alternatives to a given coal-fired generation facility now would allow the Board easily to determine whether power generated by that facility would be displaced by alternative generation resources in response to relatively small changes in its relative marginal costs. Because wholesale power generators routinely determine when to run their generation facilities based on these same analyses, these analyses provide a reliable basis for Board determinations as well.

The Board accordingly no longer needs to delve into complex antitrust-style analyses to consider the existence and effectiveness of indirect competition. It need only allow parties to present readily compiled, publicly available evidence and then apply easily understood methods regularly used by market participants in order to assess the existence and effectiveness of indirect competition for rail transportation of coal to individual coal-fired power plants.

The AAR is a trade association whose freight railroad members include U.S. Class I railroads who have been involved in coal rate cases, and it has participated actively in prior proceedings before the Board regarding the methodology to be used in assessing market dominance under 49 U.S.C. § 10707. The AAR and its members have a vital interest in ensuring that market dominance determinations act as an effective threshold test for the exercise of the Board's ratemaking jurisdiction under 49 U.S.C. § 10701 so that the Board can minimize regulation consistent with the Rail Transportation Policy at 49 U.S.C. § 10101(1-2). Given the powerful indirect competition that now constrains coal transportation rates for some coal-fired generation facilities, allowing parties to present simple and accurate evidence to identify rail movements of coal that are subject to such effective indirect competition will provide meaningful efficiencies by saving the parties and the Board from the substantial burden of undertaking unnecessary substantive determinations regarding the reasonableness of rates for the transportation of coal for electric power generation.

## SUMMARY OF ARGUMENT

Section I of this Petition summarizes the Board's position regarding the consideration of product and geographic competition. The Board has acknowledged that such indirect competition can constrain rail rates to competitive levels, but found in the past that the submission and evaluation of the requisite evidence was an unduly complex and time consuming process. As a result, the Board concluded that while product and geographic competition should be considered, it would not do so until a practical manner for the submission and evaluation of evidence of such competition could be found.

Section II of this Petition summarizes the expert views of Dr. David Reishus as provided in his verified statement accompanying the Petition. Dr. Reishus supports the Board's existing position that indirect competition, including competition in downstream markets, can effectively constrain rail rates to competitive levels and concludes that such indirect competition is being exerted on rail transportation of coal for electric power generation. Dr. Reishus examines the wholesale power and natural gas markets, showing how they have changed significantly since 1998 in ways that have in some instances increased the extent and intensity of indirect competition on transportation of coal for electric power generation. In particular, he explains how the dramatic drop in the price of natural gas precipitated by the shale gas revolution, combined with the development of deep and liquid wholesale power markets, has substantially increased the competitive pressure on rates for transportation of coal for electric power generation. Finally, Dr. Reishus demonstrates that the development and operation of competitive wholesale power markets has led to the creation of a body of publicly available data that, along with a number of well-understood analytic processes, provides the Board with multiple simple, transparent and conservative methods for identifying when effective indirect competition is exerted by the wholesale power markets on rail transportation of coal for electric power generation, and when it is not.

Although the various approaches identified and described by Dr. Reishus as possible methods to assess the existence and effectiveness of indirect competition on individual coal-fired generation facilities exercised in the wholesale power markets would apply only to traffic involving transportation of coal for purposes of electric power generation, such traffic has accounted for nearly two-thirds of the rate cases brought before the Board.[2] Thus the practical approaches identified by Dr. Reishus would apply to a meaningful number of cases, providing the efficient and expeditious process to consider indirect competition that the Board has long sought; allowing it appropriately to limit its regulatory ratemaking jurisdiction to situations in which a defendant railroad has market dominance, without adding undue burden to the regulatory process.

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[2] *See* U.S. Surface Transportation Board ("STB"), *Rail Rate Cases at the STB (1996 to Present)* (July 23, 2012) http://www.stb.dot.gov/stb/industry/Rate_Cases.htm (showing that 31 of the 49 rail rate cases brought before the Board involved transport of coal). The agency has recognized in the past that coal-specific rate guidelines are worth developing, *see Coal Rate Guidelines, Nationwide*, 1 I.C.C. 2d 520 (1985).

## ARGUMENT

### I. THE BOARD HAS NEVER DOUBTED THAT INDIRECT COMPETITION EFFECTIVELY LIMITS RAILROAD PRICING, BUT FOUND THAT CONSIDERATION OF INDIRECT COMPETITION WAS UNDULY BURDENSOME

Market dominance—defined as an absence of effective competition from other rail carriers or modes of transportation for the transportation to which a rate applies—is crucial because it is a statutory prerequisite for the Board to exercise jurisdiction over rates challenged as unreasonable. 49 U.S.C. §§ 10701(d)(1), 10707(b), (c). Congress has limited the Board's regulatory jurisdiction over rail rates to those instances where the railroad involved has market dominance, 49 U.S.C. § 10701(d)(1), in order to "allow, to the maximum extent possible, competition and the demand for services to establish reasonable rates for transportation by rail." 49 U.S.C. § 10101(1). To realize this goal, Congress directed the Board's predecessor, the Interstate Commerce Commission ("ICC"), to establish standards to define market dominance, which would then serve as "a threshold test to direct the agency's regulatory activities into areas where the public interest needs protection." *Market Dominance Determinations—Product and Geographic Competition*, Ex Parte No. 627, 3 S.T.B. 937, 938 (1998) ("*Market Dominance 1998*"), citing S. Rep. No. 499, 94th Cong., 1st Sess. 47 (1976).

In establishing market dominance standards to identify effective competition, the ICC considered the impact on rates of both direct and indirect competition. Both forms of competition constrain rail pricing because they provide the shipper with viable alternatives to relying on the defendant railroad's services. Direct competition describes the ability to ship the same commodity between the same points using a different railroad or an alternative form of transportation. Indirect competition describes other alternatives that similarly allow a shipper to avoid using the defendant railroad to ship the commodity, such as product competition (relying on a substitute product) or geographic competition (obtaining the same product from a different source, or sending it to a different destination).

The ICC initially considered only direct competition in its market dominance analyses "out of concern that the introduction of [indirect competition] would require extensive fact-finding and produce lengthy antitrust-type litigation." *Market Dominance 1998* at 939. But by 1979 the ICC, "[b]elieving that consideration of product and geographic competition evidence would not necessarily conflict with the statutory directive to make practical market dominance determinations without administrative delay[,]" changed course, and allowed carriers to introduce such evidence to demonstrate that effective competition existed. *Id.* By 1981 the ICC had entirely replaced its initial market dominance scheme and promulgated new guidelines that "explicitly provide[d] for evidence on . . . product and geographic competition" to be presented in individual cases. *Id.* at 940. In making that change the "ICC reasoned that, if evidence of product and geographic competition could practically be submitted and evaluated, Congress would want that evidence considered." *Id.*

**A.** The Board stopped considering indirect competition in 1998 because it had not found a simple and efficient way to do so

Between 1981 and 1998, the Board (and its predecessor the ICC) considered product and geographic competition in making market dominance determinations, and regularly found that such indirect competition effectively limited rates. *Market Dominance 1998* at 946 n.49. But in *Market Dominance 1998*, even though it continued to "have no doubt that in certain circumstances product and geographic competition effectively limit railroad pricing" *id.*, the Board decided it would no longer consider indirect competition because its consideration had proven unduly burdensome to both the parties and the Board. *See id.* at 946.

The Board has always appreciated that evidence of indirect competition is relevant to an accurate determination of market dominance; indeed the Board pointed out when announcing its decision that the ICC had identified effective instances of indirect competition in several cases, and that many commenting shippers conceded there were valid examples of such competition.[3] *See Market Dominance 1998* at 942 n.27, 944 n.40, 946 n.49. The Board's concern with indirect competition has always been limited to whether evidence of product and geographic competition could be submitted and evaluated in a reasonably efficient manner. Whenever the agency has believed it could be, it has considered product and geographic competition as part of its market dominance determination.[4]

The change in policy in 1998 was based on the Board's conclusion that burdensome threshold litigation on the matter of indirect competition had dissuaded shippers from bringing valid rate complaints. *Id.* at 949. The Board decided that avoiding that harm justified its decision to decline to consider potentially relevant evidence that a defendant railroad lacked market dominance, even though that might subject the railroad to an unnecessary rate determination proceeding. *Id.* at 948-49. The Board's analysis implicitly recognized that, if evidence of indirect competition could be considered without burdensome threshold litigation, then it should be.

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[3] The Board pointed to the example of "a utility that is served by two railroads, where each railroad serves a different mine capable of providing suitable coal to the utility" as an example of effective product and geographic competition many commenting shippers accepted as valid. *Market Dominance 1998* at 944 n.40.

[4] *See e.g., Special Proc. for Findings of Market Dominance*, 359 I.C.C. 735, 736 & n.7 (1979); *Market Dominance Determinations*, 365 I.C.C. 118 (1981); *Arizona Public Service Co. v. Atchison, T. & SF. Ry. Co.*, 3 S.T.B. 70, 72-74 (1998); *West Texas Utilities Company v. Burlington Northern RR Co.*, 1 S.T.B. 638, 645-46, 653-54 (1996) *aff'd sub nom. West Texas Utilities Co. v. STB*, 114 F.3d 206 (D.C. Cir. 1997); *Consolidated Papers, Inc. v. CNW Transportation Co.*, 7 I.C.C. 2d 330, 345-53 (1991); *Westmoreland Coal Sales Co. v. Denver & R.G.W. R. Co.*, 5 I.C.C. 2d 751, 756-60 (1989).

**B.** The Board's argument that consideration of indirect competition provided little benefit as a threshold test for market dominance was predicated on the absence of a simple and efficient method of identifying such competition

The Board explicitly recognized in *Market Dominance 1998* that failing to consider evidence of product and geographic competition could force railroads "to defend themselves against challenges to some rates that have been affected by indirect competition." *Id.* at 948. The Board suggested that failing to consider evidence of indirect competition might nonetheless result in little practical hardship to the rail industry because 1) shippers would be unlikely to pursue a regulatory rate challenge if there was effective indirect competition, and 2) the application of a threshold test for indirect competition provided little practical benefit because a) rates that were constrained by effective competitive alternatives would be found reasonable[5] and b) a defendant railroad would need to defend the reasonableness of its challenged rate in any event since the STB generally did not bifurcate rate challenge proceedings sequentially into initial jurisdictional market dominance and subsequent substantive rate reasonableness determinations. *Id.*

Although the D.C. Circuit affirmed the Board's decision, it was openly skeptical of the Board's first rationale. The Court was not convinced that shippers are unlikely to challenge rates where indirect competition genuinely exists, noting "[i]t is certainly plausible that some shippers would consider regulators' hands to be friendlier than invisible ones." *Ass'n of Am. R.R. v.*

[5] This rationale alone would not suffice, because a finding of market dominance is a jurisdictional predicate to any investigation into the reasonableness of a railroad's rates. Thus, the ICC stated more than once that it is inappropriate to use SAC test results to demonstrate market dominance. *See e.g.*, *Coal Trading Corp. v. B & O Railroad Co.*, 6 I.C.C. 2d 361, 372 n.11 (1990) (stating that "conclusive reliance on [pricing above SAC] to determine market dominance is inappropriate. . . . The Commission developed SAC as a measure of rate reasonableness, not as an indicium of market dominance. *Coal Rate Guidelines, Nationwide*, 1 I.C.C. 2d 520 (1985) (*Guidelines*). Section 10709(c) directs the Commission to address market dominance *before* it addresses rate reasonableness ("When the Commission finds * * * market dominance * * * it may *then* determine that rate to be unreasonable * * *.")").

*Surface Transp. Bd.*, 306 F.3d 1108, 1111 (D.C. Cir. 2002). Because the SAC test can sometimes produce counterintuitive results, a large shipper might reasonably bring and hope to prevail in a rate case even when indirect competition already is effectively constraining its rates to levels that barely exceed the jurisdictional floor.

The Board's second rationale is predicated on the assumption that consideration of indirect competition is not worthwhile because identifying it would require a lengthy process, similar in burden to the admittedly onerous task of determining whether a challenged rate is reasonable.[6] If, however, there were relatively simple and conservative indicators of effective indirect competition that could readily identify rate challenges that need not undergo a full reasonable rate analysis, then such indicators would enable substantial gains in efficiency and justify their consideration.

Consideration of indirect competition using simple and transparent methods to assess its existence and effectiveness would not deter potentially meritorious coal transportation rate challenges but likely would deter some clearly meritless challenges. Shippers considering a rate challenge may either consider that evidence themselves before bringing a rate challenge, or settle their challenge sooner than they otherwise would have after such evidence is presented by the defending railroad. Avoiding (or shortening) litigation where there is no market dominance because of indirect competition creates precisely the sort of efficiency Congress envisioned when, as the Board described in *Market Dominance 1998*, it directed the ICC to develop "a threshold test to direct the agency's regulatory activities into areas where the public interest needs protection." *Market Dominance 1998* at 938, citing S. Rep. No. 499, 94th Cong., 1st Sess. 47 (1976). And indeed the ICC has suggested that the agency is not meeting the Congressional

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[6] *See Rate Regulation Reforms*, EP 715 at 3 (served July 25, 2012) (Board recognizing the complexity and high litigation costs involved in even the simplified alternatives to full rate case).

requirement to minimize regulatory control over rail transportation when it fails to appropriately consider competitive alternatives. *See Westmoreland Coal Sales Co. v. Denver & R.G.W. R.R. Co.*, 5 I.C.C. 2d 751, 756 (1989) ("use of SAC as a test of market dominance would also contradict the Rail Transportation Policy's requirements that we minimize the need for Federal regulatory control over rail transportation," and "impose[] heavy regulatory burdens before the need for regulation has even been established[.]" (internal citations omitted)).

As further described below, there now exist simple and conservative approaches for the submission and consideration of evidence in rate cases for coal transportation to show where there is effective indirect competition for rail transportation of coal. Such approaches could quickly identify cases where effective indirect competition can safely be presumed to exist and there is accordingly no warrant for a full rate reasonableness analysis.

Under the reasoning of *Market Dominance 1998*, the introduction of simple and efficient methods for identifying indirect competition that constrains rail rates for the transportation of coal to competitive levels would compel a reevaluation of whether the inclusion of indirect competition in market dominance determinations would better serve Congressional policies expressed in 49 U.S.C. § 10101.

## II. MAJOR CHANGES IN THE WHOLESALE ELECTRIC POWER AND NATURAL GAS MARKETS SINCE 1998 AND RADICAL CHANGES IN THE MARKET DYNAMICS FOR COAL-FIRED POWER GENERATION NECESSITATE A REEVALUATION OF THE DECISION TO PRECLUDE CONSIDERATION OF INDIRECT COMPETITION IN MARKET DOMINANCE DETERMINATIONS FOR COAL MOVEMENTS

As described below, fundamental changes in the wholesale power and natural gas markets since 1998 have significantly increased the impact of indirect competition on rail rates for coal for electric power generation, while at the same time making it easier to identify the impact of indirect competition exercised in the wholesale power markets on those rates. Given these new circumstances, it is no longer justifiable in principle or under the reasoning of *Market Dominance 1998* to continue to exclude consideration of indirect competition from the market dominance analysis in rail rate cases for transportation of coal for electric power generation.

### A. Indirect competition exerted in the wholesale power markets provides effective competitive pressure on rates for transportation of coal for some coal-fired generation facilities

The Board has recognized that effective competitive pressures, precluding the justification for the exercise of its regulatory ratemaking jurisdiction, can be created by both direct and indirect competition. *See Market Dominance 1998* at 937. The crucial factor is the accurate identification of competitive alternatives that constrain a profitable increase in rail transportation rates above competitive limits, not whether such alternatives act directly or indirectly. *West Texas Utilities Company v. Burlington Northern RR Co.*, 1 S.T.B. 638, 645 (1996) ("*WTU*") (describing how the Board considered four interrelated categories of direct and indirect competition to "assess whether there are any alternatives sufficiently competitive (alone or in combination) to bring market discipline to the railroad's pricing." (citation omitted)).

Indirect competition exerted in wholesale power markets constrains rail transportation rates for coal for electric power generation to the extent that it will cause shippers of coal for electric power generation to reduce demand for rail transportation services in response to an increase in rail transportation rates. Reductions in demand for coal transportation are possible because wholesale power is a homogenous product bought, sold and dispatched based on price (or short-run marginal cost) in well-defined product markets that are generally geographically broad, typically spanning multiple states, and highly competitive.

This indirect competition is not merely theoretical. In recent years competition between coal-fired and natural gas-fired generation has been especially intense across many geographic markets because of changes in the wholesale power and natural gas markets. News reports describing competitive shifts from coal to natural gas for power generation have become commonplace, and the chief officers of major power generators have stated that the competitive fundamentals of the wholesale power markets have changed.[7] The resulting displacement of coal-fired generation by natural gas-fired generation is compelling evidence that indirect competition for rail transportation of coal for electric power generation is effectively constraining rates for such transportation to competitive levels for some coal-fired generation facilities.

**1.** Short-run marginal costs in the wholesale power markets directly determine whether coal is consumed and indirectly determine whether it is transported for electric power generation

Dr. Reishus explains in detail why the operators of coal-fired generation facilities determine how much coal to consume based on their short-run marginal costs relative to the short-run marginal costs of competing generation resources, and how this leads to the classic competitive situation in which increases in coal transportation rates to a coal-fired generation facility can lead to decreases in demand for rail transportation of coal to that facility.

[7] *See infra* notes 10, 14-16.

The short-run marginal cost of energy production from fossil fuel-fired electric generation is based primarily on the delivered cost of the fuel, and the efficiency with which the facility can convert that fuel into electricity. Because rail transportation accounts for a significant percentage of the delivered cost of coal to a coal-fired electric generation facility, the level of rail rates significantly impacts the marginal cost of energy production for that facility.

Short-run marginal costs are determinative of consumption of coal (and thus indirectly of the demand for the rail transportation of coal) because the electricity generated by burning coal is delivered into a wholesale power market in which it is essentially homogenous with all other electricity offered—while location may be relevant, the identity of the producer, plant or fuel does not determine the value of the electricity. Because electric power is essentially non-storable, and the demand for power ("load") varies substantially both within a day and across seasons, most power sources need not run at full capacity to meet the load at any given time. Only the power sources with the lowest short-run marginal costs run continuously; these are often described as the baseload supply. *See WTU*, 1 S.T.B. 638, 646 (1996) (describing a base-load power plant as one that can produce power at a lower incremental cost than alternative sources, and thus will not ordinarily drop below a certain minimum output necessary to serve its native load).

As demand for power rises above baseload supply, additional generation resources are brought on line to meet demand, and again, generation resources are brought on line on the basis of having lower short-run marginal costs than available alternatives. The highest short-run marginal cost level required to meet load at any given time can be thought of as the market-clearing marginal cost (or price) of power. A graph plotting all the available power suppliers by their short-run marginal cost will create an upward sloping "power supply curve." At any given load, you can simply move upward along the power supply curve until enough energy is supplied to meet the load requirements. The short-run marginal cost of that last facility required to meet the load becomes the market-clearing price; every facility below that on the power supply curve (as defined by each facility's short-run marginal cost) will operate (and consume fuel), and all those above it will not operate (unless they must operate for non-economic reasons).

Any coal-fired generation resource that is not a baseload supplier but is otherwise economic at least some of the time will have a short-run marginal cost at or near the market-clearing price at some load level. Assuming there are competitive alternatives available near that price, any increase in the short-run marginal cost of production at a coal-fired generation resource due to an increase in the delivered price of coal may cause that generation resource not to be dispatched and the corresponding coal not to be consumed. Under these circumstances, the railroad transporting coal to that coal-fired generation resource has no incentive to charge rates for coal transportation to that generation resource above those determined by competitive forces in the wholesale power market. So long as that coal-fired generation resource is subject to the risk of losing or gaining sales in the wholesale power market due to its delivered fuel costs a sufficient amount of the time, this risk will provide effective competitive discipline on rail transportation rates for coal to that resource.[8]

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[8] The Board is not alone in recognizing that downstream competition effectively constrains upstream market power. The U.S. Department of Justice specifically calls for consideration of the impact of downstream competition faced by buyers in their output markets in its horizontal merger guidelines. U.S. Dep't of Justice & Fed. Trade Comm'n, *Horizontal Merger Guidelines*, § 4.2.1 (2010). Similar reasoning has led the regulatory agencies and courts to reverse earlier practice, and they now recognize that barriers to entry in an upstream market (e.g., intellectual property rights) are not sufficient to create market power in a downstream market. *See Abbott Labs. v. Brennan*, 952 F.2d 1346, 1355 (Fed. Cir. 1991) (denying a monopolization claim for failure to adequately allege market power when plaintiff relied on patent protection to demonstrate market power, and citing Justice O'Connor's concurrence in *Jefferson Parish Hospital District No. 2 v. Hyde*, "A common misconception has been that a patent or copyright, a

The Board has considered this type of indirect competition in the past, treating it as a form of product competition, and stating that to demonstrate an absence of market power the railroad must show "that product competition has developed to the point where the utility can be substantially indifferent to whether it produces power from coal transported [by the defendant railroad] or obtains power from other means" such as purchasing power from the wholesale power grid. *Arizona Public Service Co. v. Atchison, T. & SF. Ry. Co.*, 3 S.T.B. 70, 73-74 (1998) ("*APS*"). Having reached a similar conclusion two years earlier in WTU,[9] the Board was clearly indicating that if product competition in wholesale power markets developed to the point where a utility could be substantially economically indifferent between producing its own power or purchasing it in the wholesale power market, this alternative would provide effective competitive discipline on rail transportation rates.

In both *APS* and *WTU*, the Board determined that the plant in question was "a base load plant" and thus would likely run most of the time, regardless of the rates charged for rail transportation of coal. *APS* at 72 and *WTU* at 653. As developed below, however, changes in the wholesale power and natural gas markets mean that today, fewer coal-fired generation resources constitute such "base load plants" that will run regardless of increasing input prices. Indeed, Commissioner Owen's concurring opinion in 1996's *WTU* predicted the Board would in the future be presented with situations in which utilities were economically indifferent between

high market share, or a unique product that competitors are not able to offer suffices to demonstrate market power. While each of these three factors might help to give market power to a seller, it is also possible that a seller in those situations will have no market power: for example, a patent holder has no market power in any relevant sense if there are close substitutes for the patented product." 466 U.S. 2, 104 (1984)).

9 1 S.T.B. 638, 653 (1996) (considering similar arguments and stating: "[t]he issue, then, is whether WTU could obtain alternative energy at prices sufficiently low to pose a meaningful threat to [defendant railroad.]").

producing their own power or purchasing it in the wholesale power market, and that this could constitute a strong showing of product competition sufficient to discipline rail rates:

> [had it been shown] that it would be economically efficient for WTU to back-down [the plant at issue] and purchase power from elsewhere—there could be a strong showing that product competition is sufficient to discipline [defendant railroad's] pricing . . . [s]ome time in the future, it should be expected that a rate complaint will be brought before this agency by an electric utility that has as a feasible alternative the ability to obtain an adequate supply of lower-cost electric power from sources other than its own generating plant. *WTU*, 1 S.T.B. 638, 680-81 (1996) (concurring opinion of Commissioner Owen).

**2.** The shale gas revolution, and the associated lower relative cost of natural gas-fired generation, has created a new competitive dynamic for coal-fired generation that may be decisive on the question of market dominance in many cases

Into the 1990s, coal was the largest fuel source for electric power generation, and coal-fired generation made up much of the baseload supply. Natural gas-fired generation tended to be a higher-cost, more flexible power supply used in periods of higher demand. This has changed in a dramatic way.[10] In the past few years, highly efficient natural gas-fired generation has in some instances significantly displaced coal-fired generation. As a result, some coal-fired power plants that were once baseload supply are no longer. In many areas and at many times, natural gas-fired generation now provides substantial competitive discipline on many coal-fired generators, thereby indirectly constraining rail transportation rates for coal to those coal-fired generators.

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[10] *See* Nicholas Akins, CEO of American Electric Power, on 4/20/2012 Quarterly Conference Call with Investors, describing how low gas prices are competing on a marginal basis with coal-fired generation, "there was always an assumption that coal is going to be lower than natural gas. Well, that's not the case, so we need to be flexible on both sides." Available at http://seekingalpha.com/article/514591-american-electric-power-s-ceo-discusses-q1-2012-results-earnings-call-transcript?part=single. Last viewed on 11/11/2012.

As described by Dr. Reishus, this shift in the wholesale power markets is due to several fundamental changes in the wholesale power and natural gas markets.

- **Natural gas-fired generation resources have developed several technological advantages over coal-fired generation resources.** Relative to coal-fired generation resources, modern natural gas-fired generation resources are faster and less expensive to build; burn fuel more efficiently; can burn fuel efficiently in smaller, more flexible generation units; and can increase or decrease production more quickly and efficiently in response to changing demand.

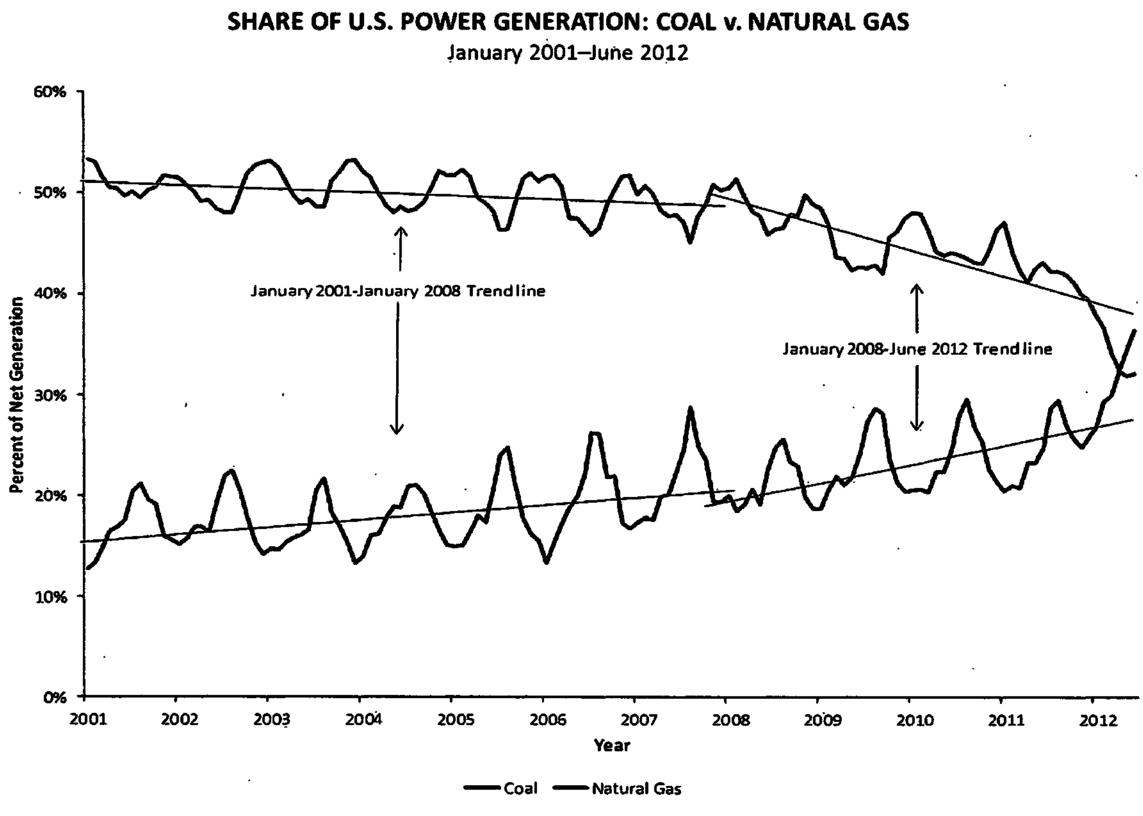
- **Because of the shale gas revolution the per-unit energy cost of natural gas-fired generation is now cheaper than that of coal-fired generation.** New extraction techniques have opened up huge new domestic supplies of natural gas, leading to a significant decrease in the cost of natural gas. Adjusting for the superior efficiency of gas-burning power plants, the amount of natural gas required to produce a kilowatt-hour of electricity is now in many cases cheaper than the equivalent amount of coal. Shale gas, which was essentially inaccessible in 1998, now accounts for 30% of U.S. natural gas production. Proven domestic natural gas reserves increased 45% between 2006 and 2010 (primarily due to reserves made accessible by the ability to extract natural gas from shale formations) and nearly all estimates suggest that natural gas production will continue to increase.

- **Existing and impending environmental regulations are likely to make coal-fired generation relatively more expensive.** Concerns about emissions from coal-fired generation raise the prospect of having to add expensive control technology to most coal-fired facilities, without imposing similar levels of additional costs on inherently cleaner natural gas-fired generation. Natural gas-fired electric generation emits fewer air pollutants per unit energy produced than coal-fired generation, including significantly less of the primary greenhouse gas carbon dioxide. The increasing efficiency of modern natural gas-fired generation resources described above means that newer natural gas-fired generation resources will emit even lower levels of pollutants per unit energy produced. Costs related to responding to environmental regulation would place additional upward pressure on the cost of coal-fired generation relative to natural gas-fired generation and consequently place downward pressure on the price of delivered coal in order for coal-fired generation to compete with natural gas-fired generation.

- **The development of deep and liquid wholesale power and natural gas markets described below has allowed the wholesale power markets to respond efficiently to changing market conditions.** Independent producers and marketers of power are able to obtain gas and sell electric power, allowing new entrants to respond quickly to market signals. Even incumbents with existing generation resources can more rapidly adjust their generation makeup by purchasing more efficient power rather than running their own, less economically efficient generation resources.

The rapidity with which the wholesale power market has shifted can be seen in Figure 4 of Dr. Reishus' verified statement, which shows the net generation of electric power by fuel source for natural gas and coal. Figure 4, which is based on U.S. Energy Information Administration data, indicates that at the start of 2008, coal accounted for over half of all power generation, while natural gas accounted for less than 20%. In April of 2012, natural gas-fired generation nearly equaled coal-fired generation for net generation.

**Figure 4**

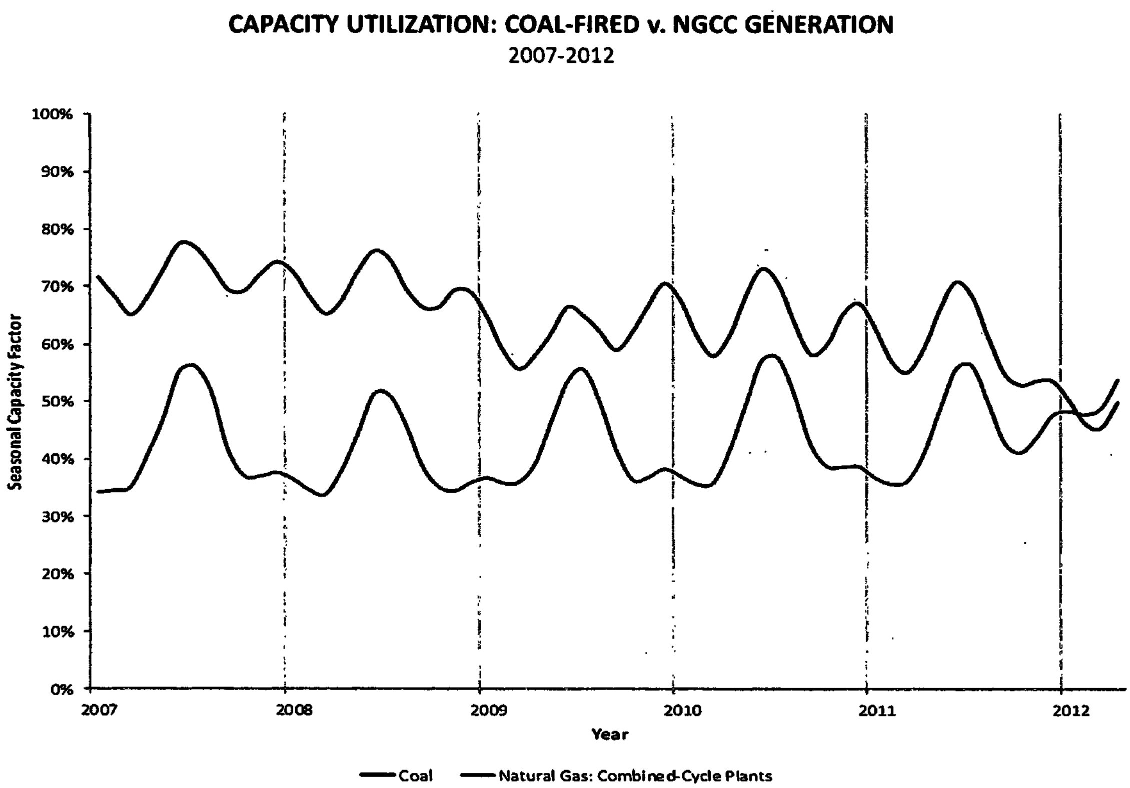



Source: U.S. Energy Information Administration, Electricity Data Browser, Net Generation Dataset.

This rapid shift demonstrates the robustness of the competitive dynamics of the wholesale power market, and also indicates that natural gas-fired generation provides a meaningful competitive alternative to coal-fired generation for many coal-fired generation resources, one that for some coal-fired generation resources can rapidly displace a significant amount of their generation output as market conditions change.

Similarly, Figure 16 of Dr. Reishus' verified statement indicates that at the start of 2008, coal-fired generation in the aggregate was operated at over 70% of its generating capacity, while the most modern natural gas-fired facilities operated at less than 40% of their aggregate generating capacity. Now, both operate at around 50% of their generating capacity, and the capacity utilization of modern natural gas-fired generation resources has surpassed that of coal-fired generation resources.

**Figure 16**




Notes: Seasonal Capacity Factor (%) uses the appropriate Summer/Winter capacity depending on the month. The months of June-September are considered Summer months and the months of October-May are considered Winter months.
Source: Ventyx, Monthly Plant Production Cost Dataset.

This again indicates the rapidity with which significant amounts of electric power production can switch from coal-fired generation to natural gas-fired generation based on market conditions, and also demonstrates that substantial additional natural gas-fired generation capacity remains available as a competitive threat to a significant amount of coal-fired generation in response to a further change in market conditions favoring natural gas-fired generation, including any relative increase in the delivered cost of coal due to rail transportation costs.

Figure 17 of Dr. Reishus' verified statement shows the power supply curve[11] for a regional wholesale power market in which, under current market conditions, many coal-fired and natural gas-fired generation resources have similar short-run marginal costs. What has primarily occurred since 2008 is natural gas-fired generation resources have moved down the power supply curve and displaced coal-fired generation resources as their short-run marginal costs decreased relative to the short-run marginal costs of coal-fired generation.[12] The exact same displacement would be seen were there an increase in short-run marginal costs for coal-fired generation resources due to increased delivered fuel costs. And the flatness of the power supply curve over the wide range of load in which coal-fired generation competes head-to-head with natural gas-fired generation in this market indicates that relatively minor increases in short-run marginal costs for coal-fired generation could result in significant decreases in capacity utilization of coal-fired generation. Under these market conditions railroads could not benefit from charging above-market rates for transportation of coal to coal-fired generation resources competing head-to-head with natural gas-fired generation resources because such pricing would simply lead to less coal being consumed. Dr. Reishus thus concludes that indirect competitive

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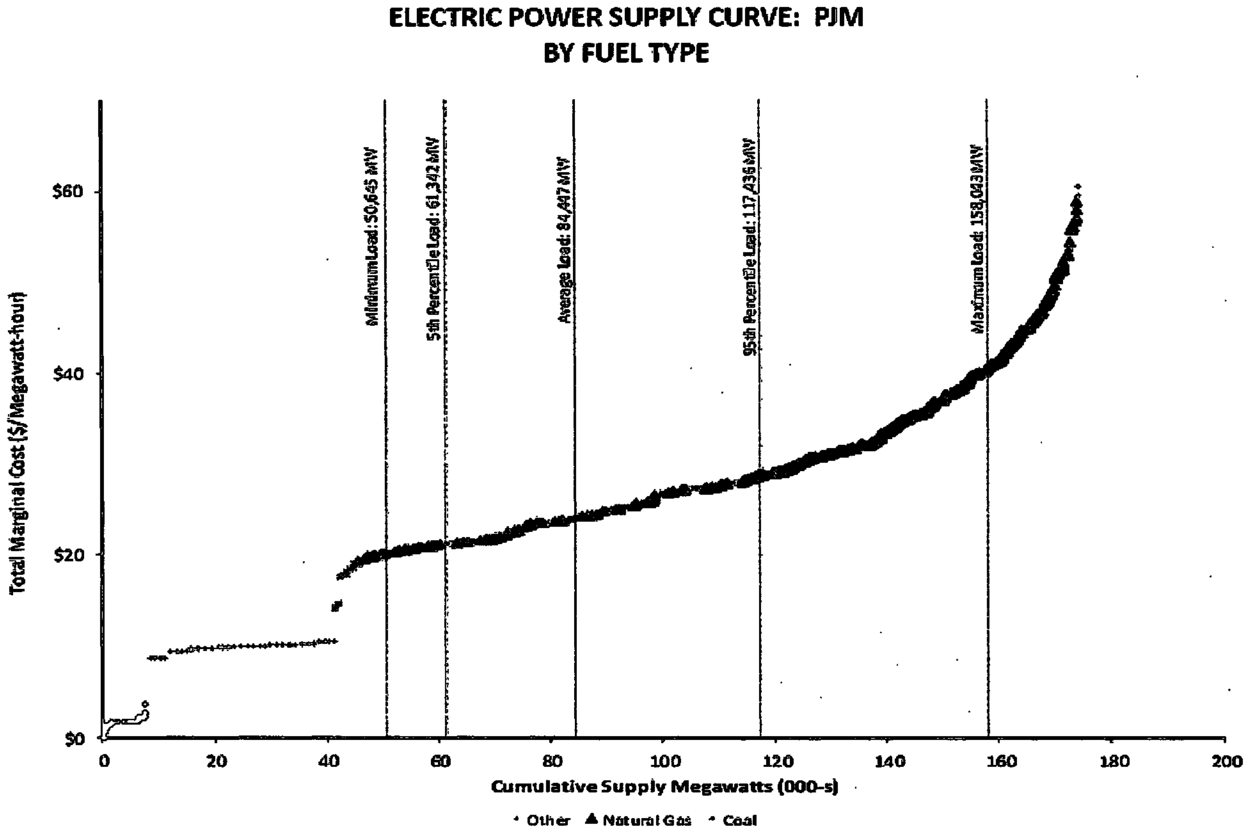
[11] *See supra* pp. 14-15 and Reishus V.S. at 50-54 for further description of power supply curves.

[12] *See* notes 10, 14 (discussing utility executives' statements regarding the displacement of coal-fired power by less expensive alternatives).

pressure exerted by natural gas-fired generation effectively constrains the rates on rail transportation of coal at some coal-fired generation resources.[13]

**Figure 17**




Note: Removed high cost peaking supply for comparability. PJM supply curve is from September 3, 2012. Total marginal cost of generators modeled by Ventyx as the sum of: fuel cost, variable operations and maintenance cost, total NOx cost, total $SO_2$ cost, total $CO_2$ cost and total mercury cost. Fuel cost sourced from FERC Form 1, EIA-412, RUS-12, EIA-906/923, EIA-423, and Ventyx primary research.
Source: Ventyx

[13] By comparison, several base-load coal-fired generation resources exhibiting much lower short-run marginal costs can be seen towards the left of the curve in Figure 17. These resources would not be constrained by the competition described above.

**3.** Deep and liquid regional wholesale power markets allow power suppliers to easily substitute between competing generation resources based on their short-run marginal costs and provide the Board with simple, transparent and conservative methods for assessing the effectiveness of indirect competition

The rapid shift from coal-fired to natural gas-fired power generation described above was made possible by the development, since 1998, of deep and liquid wholesale power markets with broad geographic scope. These markets now provide electric utilities with the "feasible alternatives" to operating certain of their own generation facilities that Commissioner Owen predicted several years ago in *WTU*, and these same markets now provide the Board with the straight-forward, publicly available data required to easily identify when and where there are "feasible alternatives" creating indirect competition for rail transportation of coal for electric power generation.

Dr. Reishus describes how the wholesale power markets (also known as bulk power markets) have developed in two primary forms. Regional transmission systems with an Independent System Operator ("ISO") or Regional Transmission Operator ("RTO") have highly-structured markets in which buyers' bids for and suppliers' offers of electric energy are cleared in a centralized single-clearing price auction that balances supply and demand. In less centralized "bilateral" bulk power markets outside of the RTO/ISO regions, load-serving utilities meet their demand requirements through self-supply or purchases in the wholesale market on a bilateral basis. In these markets, load-serving utilities have the economic incentive to select the lowest short run marginal-cost power source from either self-supply or from market purchases. In both cases wholesale power markets provide competitive discipline on wholesale electric power suppliers, and indirectly on major input suppliers for electric power generation, as lower short-run marginal cost power supply competitively displaces higher short-run marginal cost power supply.

These well-functioning bulk power markets have provided appropriate market signals for the development and production of economically efficient power generation, with market-clearing prices close to the corresponding short-run marginal costs of the least efficient generation resource needed to supply load. Because load varies substantially, wholesale power market conditions and the short-run marginal cost of production that satisfies load is determined frequently, at least several times daily. As a result, the markets have developed a body of transparent and well-understood publicly available metrics measuring the competitive forces acting in these markets. Indeed, there have developed third-party exchanges and price discovery under both types of markets, including the sale of futures and other derivatives.

Given these information-rich, deep and liquid markets, it is easy to identify in individual cases those generation resources with short-run marginal costs at or near the market-clearing prices under various load conditions, as well as those generation resources that will not run because their short run marginal costs exceed the market-clearing prices.[14] For example, in the energy market administered by PJM Interconnection L.L.C., the largest RTO in the United States (covering all or part of 13 states and the District of Columbia), certain large coal-fired generation resources—designed to run 24 hours a day, seven days a week—are now running only

[14] *See* Lynn Good, CFO Duke Energy on 2/16/2012 Quarterly Conference Call with Investors explaining that the decision to run coal resources is based on conditions in the wholesale market, "we run [our coal resources] in an economic manner. If the coal is in the money, we run them. If it's not in the money, we don't." Available at http://www.duke-energy.com/pdfs/Q42011-DUKE-Transcript-2-16-2012.pdf. Last viewed 11/11/2012.

occasionally as "competition from gas-fired plants that are cheaper to run and cleaner to operate" push them up the supply curve.[15]

Even suppliers of coal-fired generation in bilateral markets outside of the RTO/ISO regions can simply choose to purchase power from other lower-cost generation sources rather than operate their own coal-fired generation given the robust competition in these markets. For example, a publicly-owned utility in South Carolina is purchasing large amounts of gas-fired power from others rather than running all of its own rail-served coal-fired generation resources.[16]

As these examples demonstrate, the capacity utilization of a power plant gives some indication of how often its short-run marginal costs are at or below the market-clearing price. A more formal power supply curve can provide an even more precise measure of the nearest competitive alternatives a given power plant faces, and of the impact of any change in short-run marginal costs. In other words, the data used daily in wholesale power markets to determine which generation resources will be economic to operate can also be used by the Board and the parties to a potential rate dispute to quickly and accurately identify the existence and effectiveness of competitive constraints on a specific coal-fired generation resource in a particular market.

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[15] Smith, Rebecca, *Coal-Fired Plants Mothballed by Gas Glut*, Wall Street Journal, September 11, 2012. Dr. Reishus describes several additional publicly reported examples of coal-fired generation resources that have seen their generation output displaced because their short-run marginal costs are not competitive with available generation alternatives, especially natural gas-fired generation, including 10 American Electric Power coal-burning plants in Ohio, Indiana, West Virginia and Virginia, which maintain only skeleton crews on location so they can be brought into service for periods of high demand.

[16] *Gas Reliance Increases for Santee Cooper*, Electric Power Daily, September 6, 2012.

**B.** There are simple, transparent and conservative approaches that would allow the Board to identify coal-fired generation for which it is safe to presume that rail rates are constrained to competitive levels by indirect competition exerted in the wholesale power markets

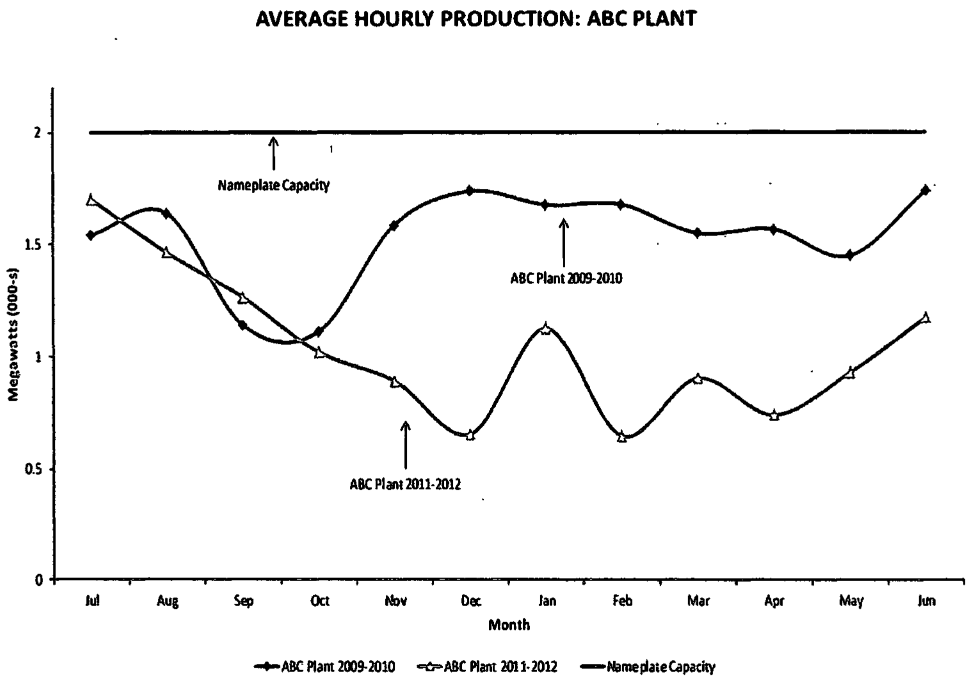
As described above, a coal-fired generator competing in a wholesale power market must decide whether to operate a given coal-fired generation resource based on the relative marginal costs of that resource and competing alternatives. That decision and its underlying analytics answer the fundamental question of whether the rail carrier has market dominance over that particular coal-fired generation resource—namely, whether there are effective competitive alternatives that constrain rates for rail transportation of coal to that resource. Dr. Reishus describes by way of example two simple approaches, based on publicly available information, and relying on forms of analysis regularly relied upon by market participants, that would indicate whether and to what extent rail rates for a particular coal-fired generation resource are constrained by indirect competition exerted in the wholesale power market. A complainant in an individual case might be able successfully to rebut this indication with particularized facts unique to the coal-fired generation resource at issue. But even in those cases, the Board's ability quickly and accurately to identify the likely existence and effectiveness of indirect competition would allow it to determine the effect of indirect competition on rail rates without undue delay or burden, resolving the dilemma the Board identified in *Market Dominance 1998.*

**1.** Actual changes in coal-fired and natural gas-fired generation output

The most straight-forward evidence of indirect competition exerted in the wholesale power markets on an individual coal-fired generation resource is evidence of changes in the generation output of that resource in response to changes in market conditions. Dr. Reishus explains that the presence of such evidence is a clear indicator of effective indirect competition that is constraining rail rates for the transportation of coal to some coal-fired generation resources. As discussed above, the last four years have provided a natural experiment in which the capacity utilization of many coal-fired generation resources has decreased while that of natural gas-fired generation has increased based on changes in their relative short-run marginal costs. Coal-fired generation resources that saw their generation output displaced by natural gas-fired generation during that time are clearly subject to competitive alternatives, and an increase in rail rates would lead to similar displacement and reduced demand for rail transportation of coal. This was the result publicly reported for coal-fired generation resources like the examples discussed above and the publicly reported examples of other coal-fired generation resources facilities discussed in Dr. Reishus' verified statement. Such publicly reported examples constitute evidence meeting the standard for demonstrating an absence of market dominance that the Board described in *APS*—a showing that product competition has developed to the point where a generation supplier can be substantially economically indifferent as to whether it produces power from its own coal-fired generation resource or obtains it elsewhere. *APS*, 3 S.T.B. 70, 73-74 (1998).

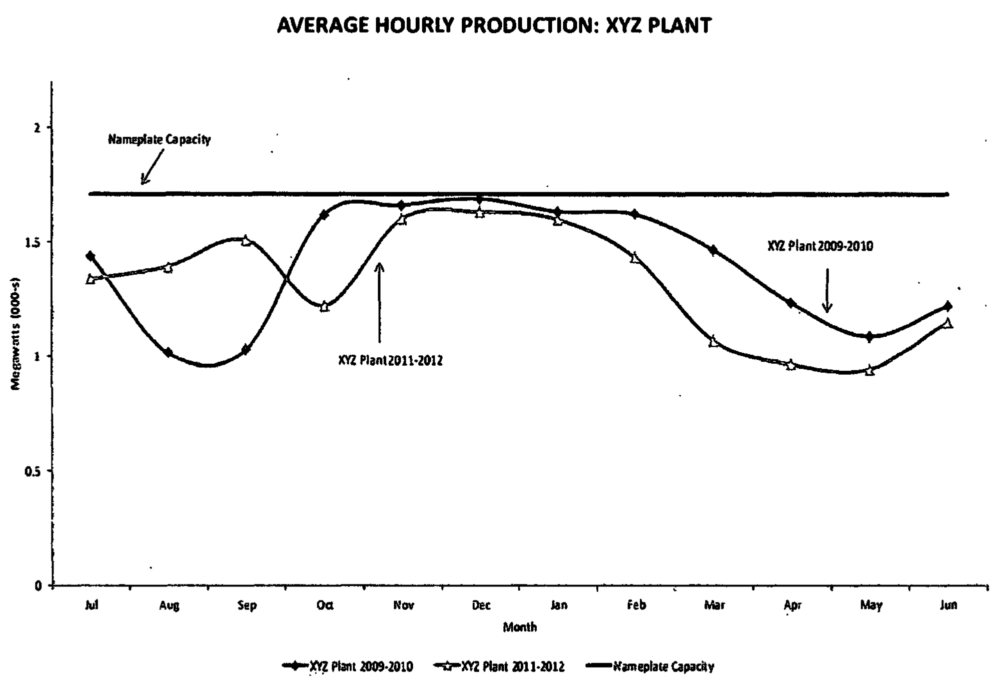
Dr. Reishus provides an example of what such an analysis might look like in Figures 20 and 23 of his verified statement. These figures show the average hourly generation output at two rail-served, coal-fired power plants: Plant ABC (Figure 20) and Plant XYZ (Figure 23). Each figure compares that plant's output over two periods: 2009-2010 represents a baseline period before the full impact of the shale gas revolution was felt; 2011-2012 represents the affected period, when the impact of declining marginal costs for natural-gas fired generation resources caused them to increase their output and displace the output of many coal-fired generation resources.

## Figure 20




Source: Ventyx, Unit Generation and Emissions Dataset.

## Figure 23




Source: Ventyx, Unit Generation and Emissions Dataset

Figure 20 indicates that Plant ABC is subject to effective indirect competition for rail transportation of coal. The significant drop in output at Plant ABC during the affected period indicates that output from Plant ABC was displaced, most likely by lower cost output from natural gas-fired generation resources. In contrast, Figure 23 shows that Plant XYZ was not subject to effective indirect competition, as its output was relatively unaffected by the declining price of natural gas-fired generation in the latter period. Coal-fired generation resources like Plant ABC, which are subject to displacement based on decreases in the marginal cost of alternative generation resources, would experience similar drops in output if their own marginal costs were to increase. Such drops in output necessarily lead to decreased demand for inputs, and thus the prices for inputs for such plants (including prices for delivered fuel) are effectively constrained by indirect competition.

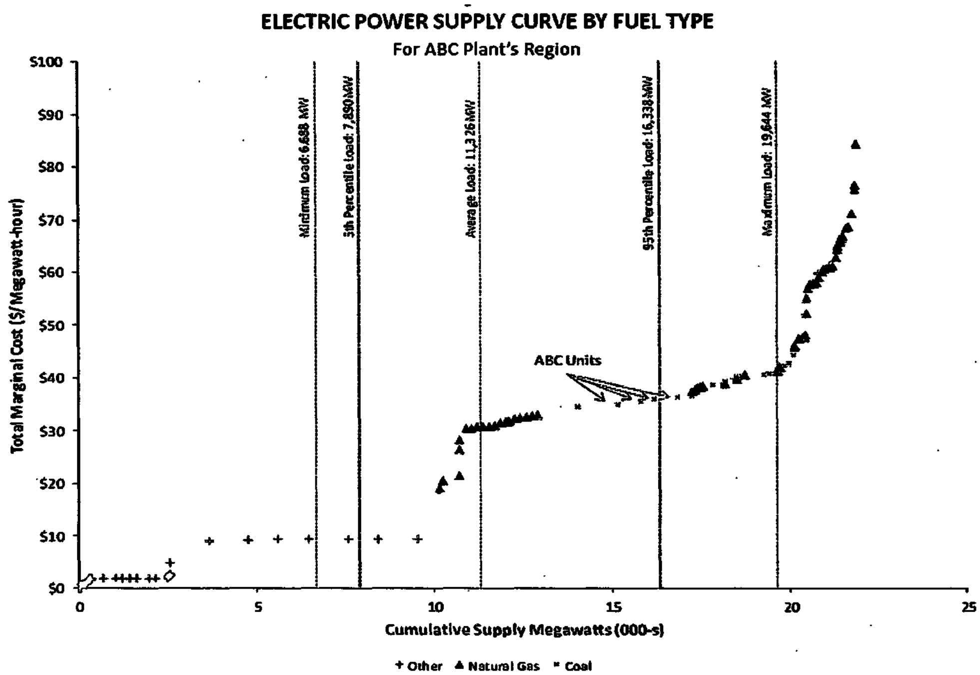
In circumstances like these, the Board can rely upon simple data regarding generation output levels to identify rates for rail transportation of coal to coal-fired generation resources that are and are not subject to indirect competition in the wholesale power markets. More nuanced versions of such production data could be employed to further refine the analysis, but the point for present purposes is that the requisite production data to perform this straight-forward analysis is readily available.

**2.** Wholesale power supply and capacity factor curves

A second simple indicator of the existence and effectiveness of indirect competition exercised in the wholesale power markets on an individual coal-fired generation resource is the wholesale power supply curve, a commonly-employed graphical representation of the short-run marginal costs of the alternative generation resources available in a particular wholesale power market, prepared using information about delivered fuel prices and generation resource operating characteristics, such as a fossil fuel-fired generation resource's heat rate (the efficiency with which a resource can convert fuel into heat and then into electricity). By providing a comparison of the relative short-run marginal costs of the competitive alternatives, the power supply curve allows one to predict, *a priori*, the results of the natural experiment described above. The relative positions of various generation resources on the power supply curve indicate where a particular resource's short-run marginal costs fall amongst its potential competitors. For example, for a coal-fired generation resource that is not a baseload supply resource, and is found on the "flat" section of the supply curve (where the price elasticity of supply is greatest), small changes in short-run marginal costs can lead to a significant change in its location on the supply curve, and thus, this resource and its upstream suppliers are competitively constrained by indirect competition. Moreover, as Dr. Reishus explains, one can estimate the generation resource's new location on the supply curve given a change in input costs (including rail rates where applicable), and thus predict how the resource's capacity utilization (and therefore coal consumption and related demand for coal transportation services) would be altered by such a change.

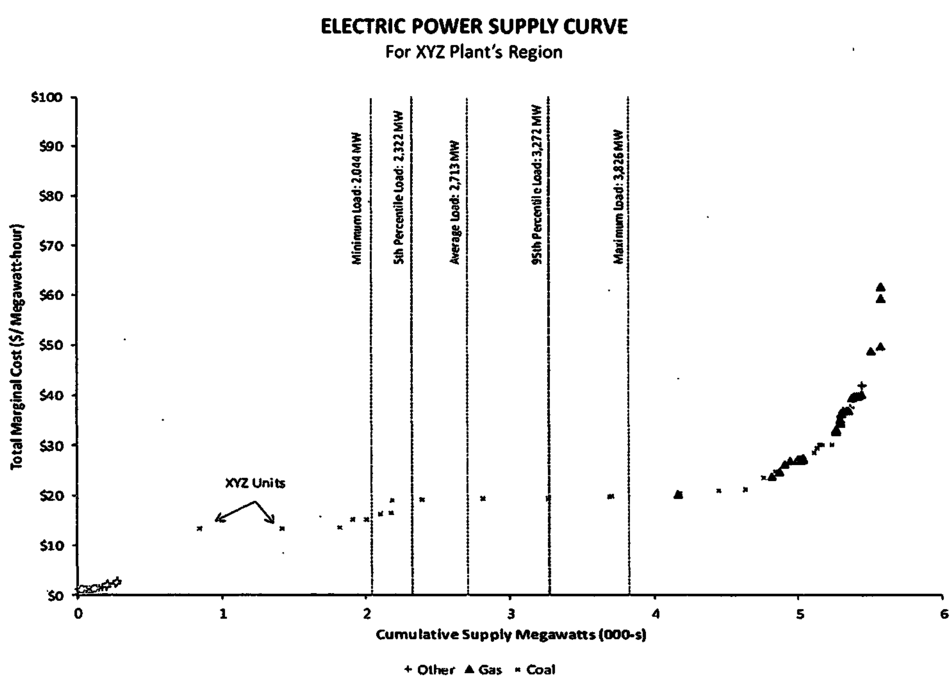
Dr. Reishus's Verified Statement includes an example of how the wholesale power supply curve can indicate the presence of effective indirect competition. He analyzes Plants ABC and XYZ using the wholesale power supply curves in their relevant markets, and shows why the different responses of the two plants to increased competition from natural gas-fired generation were entirely predictable. Figure 21 indicates that the coal-fired resources of Plant ABC are found in the flat section of the supply curve, and are surrounded on both sides by alternatives (including many natural-gas fired resources) with similar marginal costs. It is thus not surprising that, as shown in Figure 20 above, Plant ABC saw a significant decrease in production when the marginal cost of natural-gas fired generation decreased.

## Figure 21




Note: Removed high cost peaking supply for comparability. Supply curve is from September 3, 2012. Total marginal cost of generators modeled by Ventyx as the sum of: fuel cost, variable operations and maintenance cost, total NOx cost, total $SO_2$ cost, total $CO_2$ cost and total mercury cost. Fuel cost sourced from FERC Form 1, EIA-412, RUS-12, EIA-906/923, EIA-423, and Ventyx primary research.
Source: Ventyx

## Figure 24




Note: Removed high cost peaking supply for comparability. Supply curve is from September 3, 2012. Total marginal cost of generators modeled by Ventyx as the sum of: fuel cost, variable operations and maintenance cost, total NOx cost, total $SO_2$ cost, total $CO_2$ cost and total mercury cost. Fuel cost sourced from FERC Form 1, EIA-412, RUS-12, EIA-906/923, EIA-423, and Ventyx primary research.
Source: Ventyx

In contrast, Figure 24 indicates that Plant XYZ is part of the baseload supply, and faces little if any competition from natural-gas fired generation alternatives with similar marginal costs. Consistent with what Figure 23 shows actually happened, the supply curve in Figure 24 predicts that Plant XYZ is unlikely to respond to a decrease in the cost of natural-gas fired generation. Power supply curves thus provide the Board another simple and effective tool to identify coal-fired generation resources subject to displacement by alternative resources in response to a change in marginal costs, *i.e.* those resources subject to effective indirect competition.

A similar indicator of the existence and effectiveness of indirect competition on rail transportation rates for an individual coal-fired generation resource is a capacity factor curve, which depicts generation resources based on their capacity factors. Resources with the lowest short-run marginal costs operate most frequently and thus have the highest capacity factors, while resources with the highest marginal costs operate least frequently and have the lowest capacity factors. (Thus, the capacity factor curve is like a reverse mirror image of the power supply curve.) As with the power supply curve, the capacity factor curve can show whether a given generation resource is subject to competitive pressures that constrain it and its upstream suppliers, as a relative increase in the short-run marginal costs of a resource subject to such competitive pressures will result in it operating less frequently (and perhaps much less frequently as has been the publicly reported case with some coal-fired generation resources whose short-run marginal costs have increased relative to gas-fired generation) if it is on a relatively flat part of the capacity factor curve.

Dr. Reishus's Verified Statement illustrates how a capacity factor curve could be used to evaluate the impact of indirect competition on rail transportation rates for coal delivered to Plants

ABC and XYZ. He shows where these plants are located on the capacity factor curve in their respective markets in Figures 22B and 25B attached to his verified statement. The capacity factor curves show that small changes in the marginal costs for Plant ABC will result in large changes in its capacity factor, whereas this would not be the case for Plant XYZ. Dr. Reishus further demonstrates this point by providing historical capacity factor curves from a year earlier (Figures 22A and 25A), which show that Plant ABC has in fact operated less frequently over time as its marginal cost of production has increased relative to the marginal costs of available alternative generation resources. Thus, this capacity factor analysis not surprisingly reinforces the analysis and conclusions based on the power supply curves.

As with the direct evidence provided by observing actual responses to changing market conditions, where the wholesale power supply and capacity factor curves predict that generation output of a coal-fired generation resource will respond substantially to competition from competing generation resources in response to an increase in rail rates, this indicates that rail rates for coal delivered to that coal-fired generation resource are effectively constrained by indirect competition exerted in the wholesale power market.

### 3. The analyses suggested by Dr. Reishus are regularly performed and easily reproduced using public data

The sample analyses provided by Dr. Reishus demonstrate that simple indicators that rely on publicly available information can accurately distinguish between situations in which indirect competition exerted in wholesale power markets can competitively discipline rail rates for coal delivered for coal-fired power generation, and those in which regulatory oversight remains appropriate. Dr. Reishus describes how the increased standardization of the publicly collected and reported data has made previously difficult analysis of competition in the wholesale power markets commonplace. He explains that data on generation output and capacity factors, load, marginal cost, and fuel cost, at both the market and individual plant level are available from a broad range of reliable sources including the U.S. Energy Information Agency, the EPA, and independent market monitors for each RTO/ISO, and that the vast quantity of data available has led to the development of private data aggregation services that organize this data for regular use by market participants.[17] It would be a straight-forward, quick, and inexpensive exercise for shippers considering a rate challenge to undertake such an analysis of indirect competition exercised in the wholesale power markets before filing a complaint with the Board. Consideration of this indirect competition as part of a threshold market dominance analysis could therefore help direct the parties—and the Board's regulatory resources—more effectively towards circumstances in which the public interest needs protection.

While many rates for the transportation of coal to electric utilities would not be found subject to such indirect competition, the simplicity of the analysis, and the significant burden of undertaking a full rate reasonableness determination, justifies consideration of this evidence. Under the reasoning of *Market Dominance 1998*, the ready availability of simple and transparent indicators of effective indirect competition requires a reevaluation of the Board's conclusion that consideration of indirect competition would create an undue burden on the regulatory process.

## CONCLUSION

In 1998, the Board decided to no longer consider indirect competition in making market dominance determinations because it found that the submission and evaluation of evidence of product and geographic competition had proven to be a complex and time consuming process that placed undue burden on the parties and the Board. The subsequent development of deep and liquid wholesale power markets allows the complex and time-consuming process the Board

[17] *See* Reishus V.S. at 67-69.

expressed concerns about in *Market Dominance 1998* to be replaced by simple and transparent indicators based on publicly available and transparent information and well-understood analyses that are regularly utilized by participants in the wholesale power markets. The same developments in the wholesale power markets, as well as revolutionary changes in the natural gas markets that have resulted in major structural shifts favoring natural gas-fired generation in many instances, have significantly increased the degree to which indirect competition exerted in the wholesale power markets acts as an effective competitive constraint on the rates for the rail transportation of coal for electric power generation for many coal-fired generation facilities, meaning that railroads lack the market dominance over those facilities necessary to provide the Board with jurisdiction over their rates.

The Board has never doubted that indirect competition should be considered in reaching market dominance determinations, so long as such consideration would not unduly burden the regulatory process. The changed circumstances in the wholesale power markets—directly relevant to the basis of the Board's decision in *Market Dominance 1998*—compel reevaluation of whether the consideration of indirect competition exercised in the wholesale power markets in the Board's market dominance analysis for the transportation of coal to power generation facilities would better serve the Congressional policies expressed in 49 U.S.C. § 10101. The Board should initiate a rulemaking proceeding and propose the reintroduction of indirect competition as a factor that may be considered during market dominance analysis under 49 U.S.C. § 10707 for rate challenges regarding the rail transportation of coal to coal-fired electric power generation facilities.

Respectfully submitted,

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BEFORE THE

SURFACE TRANSPORTATION BOARD

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PETITION OF THE ASSOCIATION OF AMERICAN RAILROADS

TO INSTITUTE A RULEMAKING PROCEEDING TO

REINTRODUCE INDIRECT COMPETITION AS A

FACTOR CONSIDERED IN MARKET DOMINANCE DETERMINATIONS

FOR COAL TRANSPORTED TO UTILITY GENERATION FACILITIES

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# VERIFIED STATEMENT

# OF

# DAVID A. REISHUS

## Table of Contents

## I. INTRODUCTION

My name is David Reishus. I am an economist and currently a Senior Vice President at Compass Lexecon, the economic consulting subsidiary of FTI Consulting. I have consulted for many years on the economics of railroad transportation, natural gas, and electric power markets. I have provided testimony or other submissions to courts or relevant regulatory authorities, such as the Surface Transportation Board (the "Board" or the "STB") regarding the economics of market competition in each of these industries. My statement of qualifications is attached.

I have been asked to identify market forces that provide competitive restraints on rail rates for the transportation of coal to coal-fired generation facilities. In particular, I have been asked to consider how indirect competition in the downstream wholesale power markets may constrain such rail rates to competitive levels, how recent fundamental changes in the downstream wholesale power markets and in the natural gas markets affect that analysis, and whether practical methods exist for identifying rates that are effectively constrained by such competition.

## II. SUMMARY OF FINDINGS

Changes in the wholesale electric power markets and the natural gas markets, along with strengthened environmental regulation, have fundamentally altered the competitive relationship between coal-fired and natural gas-fired electric power generation in the U.S. Coal-fired generation, which has been the primary source of electric power production in the U.S. for decades, has seen its share fall while natural gas-fired generation has risen rapidly. This trend has accelerated in the last three years as large new supplies of low-cost natural gas have reached the marketplace. As a result, in many locations the ability to generate and sell power in the wholesale electric power markets from coal-fired generation resources turns on the relative delivered costs of natural gas and coal to power generators. This competition in the wholesale power market has led to a reduction in the volume of coal consumed for electric power generation, and a concomitant reduction in demand for transportation of coal by railroads. Thus, in many locations direct competition between coal-fired and natural gas-fired generation provides an effective constraint on rates for rail transportation of coal for some coal-fired generation resources to competitive levels.

Apart from the fall in natural gas prices, other factors in the wholesale electric power markets have enhanced competition between coal-fired and natural gas-fired generation. The technology of natural gas-fired generation has improved substantially over the last twenty years, leading to large additions of highly efficient natural gas-fired generation resources. Natural gas-fired generation has the inherent advantage of producing less pollution, including greenhouse gases, and thus requires little environmental remediation compared to coal-fired generation. The evolution of market institutions and regulation has also led to wholesale electric power markets that in many locations have become efficient and transparent enough that generation resources compete fiercely on price in a way they did not in 1998. Since the delivered cost of the fuel consumed represents most of the short-run marginal cost (hereinafter "marginal cost") for coal-fired and natural gas-fired generation, price competition in the wholesale electric power markets has led to substantial price competition on a delivered-cost basis for fuels.

Despite the improving relative position of natural gas versus coal for electric power generation, coal had until relatively recently maintained an edge for high-volume power generation due to the higher cost of the energy content of delivered natural gas versus coal. The shale gas revolution, which only in the last five years has had significant market effects, has added large new supplies of low-cost gas, particular in regions such as the Northeast where natural gas had previously been relatively expensive compared to coal due to transportation costs. Advances in drilling and production methods—horizontal wells using hydraulic fracturing—have opened up vast quantities of U.S. natural gas resources that had previously been unusable. The result has been U.S. natural gas prices that make natural gas an economically significant alternative to coal for use in electric power generation. While natural gas prices tend to be volatile, over the past few years, and especially this year, natural gas prices have been low enough to result in substantial displacement of coal-fired generation with natural gas-fired generation in wholesale power markets.

Conditions in natural gas and wholesale electric power markets make competition between coal-fired and natural gas-fired (and other) generation highly relevant to the competitive setting for rail transportation of coal for electric power generation. As a result of the regulatory oversight of market competition in wholesale electric power markets, standardized, detailed, public information on the competitiveness of local wholesale electricity markets has become available over the last decade. In addition, due to various data collections, there is readily available and highly detailed information (e.g., hour-by-hour generation information on fossil-fuel-fired generation resources) that permits straightforward analysis of the competitiveness of wholesale electric power markets, and thereby the ability of indirect competition generated in those wholesale electric power markets to effectively constrain rates for rail transportation of coal used for power generation to competitive levels.

I present two alternative approaches, both based entirely on simple analyses using publicly available information, and both capable of discriminating between those circumstances and markets in which indirect competition substantially constrains delivered coal prices and corresponding rail transportation rates, and those in which it does not.

## III. ECONOMICS OF COMPETITION IN TRANSPORTATION OF COAL FOR ELECTRIC POWER GENERATION

Coal has traditionally been the most important fuel for electric power generation and is the largest single commodity carried by rail. Until recently, half of U.S. electric power was produced through the burning of coal.[1] And railroads carried 70% or more of the domestic coal used in electricity generation.[2] In 2009, coal transportation represented 47% of the tonnage and accounted for 25% of gross revenue for Class I Railroads.[3]

Coal-fired generation plants are also generally large in scale; there were fewer than 600 primarily coal-fired generation plants in the U.S. in 2010.[4] As such, an individual generation facility may require a railroad to carry two million tons or more of coal a year, resulting in bills for rail transportation of coal to an individual generation facility that can run into the millions of dollars annually. Not surprisingly, rail transportation rates for coal have been a focus for dispute and regulatory oversight. Since 1996, nearly two-thirds of the rate cases filed before the Board have involved the transportation of coal to coal-fired generation facilities.[5]

### A. Sources of Competition in Transportation of Coal for Electric Power Generation

Modern regulatory policy for freight rail transportation has relied on market forces, where effective, to ensure that rail rates are reasonable. Only when market forces are ineffective does rail regulation rely on administratively determined

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1 U.S. Energy Information Administration, "Net Generation for All Sectors," January 2001-June 2012.

2 U.S. Energy Information Administration, "Rail Coal Transportation Rates to the Electric Power Sector" ("EIA Rail Coal Study"), released June 22, 2001.

3 Association of American Railroads, "Railroads and Coal," August 2010 at 3.

4 U.S. Energy Information Administration, *Electric Power Annual 2010*, November 2011, at Table 5.1. In addition to the power generators identified above, a small portion of the electric power derived from coal came from combined heat and power facilities that tend to operate on a much smaller scale.

5 "Rate Case Result Summaries," http://www.stb.dot.gov/stb/industry/Rate_Cases.htm accessed September 14, 2012.

maximum rates. Primary reliance on market forces has been extraordinarily successful and has resulted in freight railroads that "are universally recognised in the industry as the best in the world" with rates among the lowest in the world.[6] This regulatory system, and its beneficial results, depends on accurately and efficiently distinguishing circumstances in which market forces do and do not effectively constrain rail rates to competitive levels.

Market forces effectively constrain rail rates through a variety of mechanisms. The crucial factor is the existence of some competitive market alternative(s) that effectively constrains a profitable increase in the rate for particular rail traffic above competitive levels. These market alternatives can take the form of direct competition, competition for the particular origin-to-destination movement from other railroads or transportation modes, or indirect competition, such as product and geographic competition, in which other competitive alternatives prevent a railroad from exercising market dominance over particular traffic.

***Direct Competition***

Direct competition comes from alternative transportation options that can economically provide service between the same origin and destination. In the rail industry, direct competition generally takes one of two forms: intra- or intermodal competition. As the name implies, intramodal competition is competition from another railroad (or combination of railroads offering interline service) offering

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6 "American Railways: High-speed railroading," *The Economist*, July 22, 2010; Association of American Railroads, "Overview of America's Freight Railroads," May 2008, at 1.

competing service between the same origin and destination points as the incumbent railroad. By contrast, intermodal competition refers to competition from another transportation mode (or combination of modes) capable of serving the same origin-to-destination pair. Intermodal competition can come from trucks, barges, ships, pipelines, or a combination of these. The competitive impact of direct competition on rail rates is clear: rail rates are constrained to those set by competition whenever shippers have the ability to switch from rail to an economically reasonable alternative transportation option serving the same origin and destination. If a railroad establishes rates above the service-adjusted rates of a transportation competitor, the shipper will likely utilize the competitor. The incumbent railroad loses the traffic and revenue, and any contribution that revenue would have made to covering fixed costs above the variable cost for the movement.

*Indirect Competition*

Direct competition is not the only form of competition that can effectively constrain rail rates to competitive levels. Indirect competition, in the form of geographic and product competition, can also—and often does—provide powerful discipline on rail rates. Geographic competition arises from a shipper's ability to utilize different geographical origins or destinations, served by alternative transportation options, to satisfy its business needs. A shipper that can receive products from geographically disperse origin points or ship products to geographically disperse destination points can use these alternatives to constrain the rates quoted by the incumbent rail carrier.

Indirect competition is also exerted through product competition—the ability to substitute alternative products or uses for products currently shipped by the incumbent railroad. Shippers who have flexibility in the markets into which they sell products or flexibility in the products they use in their own production processes must be offered rail rates that reflect these effective competitive alternatives. The incumbent railroad cannot set rates higher than the cost of the next-best effective competing alternative, or the traffic and the accompanying revenue contribution will be lost. Regardless of the source of the competition—direct or indirect—railroads have no economic incentive to set their rates at levels that would cause them to lose business entirely or to reduce profits through the loss of traffic and associated revenues.

### B. Competition in Wholesale Power Markets Provides Effective Competitive Constraints on Rail Rates for Coal Used for Some Electric Power Generation

Competition in wholesale power markets has always had the potential to constrain rail rates for transportation of coal delivered to coal-fired generation resources. That potential has been more fully realized over the past decade as 1) deep and liquid wholesale power markets developed, allowing potential coal shippers ready access to, notably natural gas-fired, alternative power sources, and 2) the shale gas revolution created an economically viable alternative source of power for many coal-fired generators. I first describe how competition between generation resources in the wholesale power markets can constrain rail rates for coal, and then explain how recent changes in those markets have dramatically increased the impact of that indirect competition on rail rates, which indirect competition, in some situations, provides an effective competitive constraint on rail rates.

As further explained below, wholesale electric power is bought and sold (or self-supplied) in centralized or bilateral wholesale markets in which, in most cases, the source of wholesale electric power, consistent with the economics of supply, competes with other power sources based on the relative (short-run marginal) costs of producing that power. Apart from locational differences, electric power is a fungible product. The physical electric power produced is the same, regardless of the initial energy source—be it coal, natural gas, oil, uranium, water, wind, biomass, geothermal energy, or sunlight—used to produce the power. Clearly the different technologies used to produce this power affect the level and timing of electric power production, but the power itself competes on an equal footing.[7]

For fossil fuel-based power generation, such as power produced by burning coal and natural gas, the short-run marginal cost of production is mostly determined by the delivered cost of fuel to the generation resource, the energy content of that fuel, and the thermodynamic efficiency with which the generation "machine" can convert the energy in the fuel into heat, and then into electric power.

[7] Generation facilities of different types can provide other ancillary services used to maintain the reliability of the bulk power grid, such as maintaining voltage on the transmission grid. Because electricity is generally not storable at this scale, non-power-producing generation capacity is utilized in different ways to ensure reliability, so that fluctuating demands for electricity are supplied in real time. Such ancillary services represent a small part of the revenue stream to generators and for the most part do not depend on delivered fuel costs.

(Some small amount of variable operation and maintenance costs also adds to the marginal cost of electric power.) A common measure of the thermodynamic efficiency of a fossil fuel plant is the "heat rate" which compares the amount of energy in the fuel, measured in British thermal units ("Btu"), required to produce a unit of electric energy, measured in kilowatt-hours ("kWh"). The less energy required in the fuel to make a kilowatt-hour, the greater the fuel efficiency and the lower the heat rate.

Because the power itself is fungible, the ready opportunity to obtain power from alternative sources in the wholesale power market provides effective competitive pressure on the suppliers of fuel inputs to coal-fired generators in that market. In 2011, the average cost of coal delivered to the electric power sector was $47/ton.[8] Depending on source and destination, the share of transportation costs can make up 10% to over 65% of the delivered cost of coal.[9] Because of the large volume of coal shipped by rail and the high share of costs associated with its transportation, "changes to rail transportation costs can have a significant impact on the delivered price of coal and indirectly on electricity prices charged to consumers."[10] Thus, coal-fired generation that pays above-market rates for rail transportation of coal will be less competitive against other forms of competitively

8 U.S. Energy Information Administration, *Electric Power Monthly*, September 2012 at Table 4.1.

9 "Want to understand coal plant economics? Don't forget transportation costs," SNL Financial, August 2, 2012. EIA Rail Coal Study reports that in 2008 rail transportation accounted for 20% of total delivered cost of all coal but could be as high as 59%.

10 EIA Rail Coal Study at 1.

priced generation. When and where such competitive alternatives exist, this competition can and should constrain rail rates for coal for coal-fired generation to competitive levels.

Effective indirect competition on rail rates requires a competitively priced alternative to coal-fired generation subject to those rates, and a market capable of delivering that alternative. Both have developed over the past decade. As will be discussed further below, technological changes have dramatically altered the cost structure of natural gas-fired generation, such that natural gas generation is in many circumstances an equal and sometimes superior competitor to coal-fired generation. At essentially the same time that natural gas developed into a broadly viable alternative to coal for electric power generation, developments in the organization and operation of wholesale electric power markets have made it easy for power generators to access alternative sources of power. The result is that indirect competition from natural gas-fired generation now effectively constrains rail transportation rates of coal for some coal-fired generation facilities.

As discussed further below, natural gas-fired and coal-fired generation compete over a range of electricity demand conditions. In periods of high demand, both coal and natural gas-fired generation may be fully operating, while at periods of low demand, neither may produce power. Over some substantial range of demand conditions, however, natural gas-fired generation can substitute for coal-fired generation, depending on location and costs. For natural gas-fired generation to constrain the pricing of delivered coal, including the charges for rail transportation, it is not necessary for power produced by natural gas-fired and coal-fired generators to compete at all times (i.e., in all demand conditions), only for them to compete some economically relevant portion of the time. Since coal-fired generation plants typically stockpile one to three months of coal on-site, rail transportation providers cannot discriminate in the price of their transportation service to a particular coal-fired generator based on when power from that generator competes with natural gas-fired generation and when it doesn't. Rail transportation rates for a coal-fired generator that are too high result in lost traffic on a rail movement of coal to that generator and an associated loss of coal transportation revenue and profits as that higher-marginal-cost coal-fired generator is displaced by natural gas-fired generation during periods in which the coal-fired generator competes with natural gas-fired generation. Because the railroad bears the competitive risk of lost coal traffic, for some coal-fired generation facilities natural gas-fired generation provides an effective competitive alternative that constrains rail transportation rates for coal for electric power generation to competitive levels.

In the next section, I describe in more detail the operation of the wholesale electric power markets and the natural gas markets with respect to the competitive pressure placed on transportation of coal used for power generation. In the final section, I describe possible alternative methods, based on readily available information, for analyzing the effectiveness of competitive forces constraining rail rates arising from indirect competition, primarily from natural gas-fired generation, in wholesale electric power markets.

## IV. WHOLESALE ELECTRIC POWER MARKETS

### A. Competition in Wholesale Power Markets

*Characteristics of Physical Demand and Supply*

Wholesale electric power consists of power supplied into and delivered from a network of high-voltage transmission lines over large interconnected electrical systems made up of generation and transmission facilities. These systems are referred to as "bulk power" systems. One central aspect of electric power is that it must be consumed almost simultaneously with its production; there is currently very limited ability to store electricity on a large scale. The physical supply of power must meet the physical demand for power (also known as "load") at all times. The flow of electric power follows the laws of physics; real-time adjustments in the dispatch of electric power are required to maintain the balance between generation and load, and maintain the stability of the electricity transmission grid.

The demand for power originates from residential, commercial, and industrial customers. Delivery of that power involves the step-down from the high-voltage transmission network underlying the bulk power system into lower voltage distribution systems for delivery to end-users. The retail delivery of wholesale power is performed by thousands of utilities and retail power distributors across the country.

Demand or load varies substantially across time, both within a day and across seasons. Figure 1 shows the daily variation in load (i.e., demand for power) over a typical summer week. Likewise, as seen in Figure 2, load varies across seasons, with demand typically peaking on an annual basis in the summertime, with a smaller peak in the winter. Since supply of power must equal concurrent physical demand, the production of electric power must vary in the same manner as demand, and appropriate and adequate generation resources must be in place to meet this variation in demand. There must therefore be sufficient generation capacity to meet the absolute peak demand with a reserve margin for safety purposes. It follows that for much of the time generation facilities will not be running or will be running below capacity.

### *Organization of Wholesale Power Markets*

Wholesale electricity markets in the U.S. fall into two types, based on location. The first type incorporates a centralized entity, known as an RTO/ISO,[11] that manages the bulk power system (i.e., the high-voltage transmission grid and interconnected generation resources) and associated centralized or organized markets. Figure 3 shows those regions covered by the various RTO/ISOs. These regions account for roughly 59% of the U.S. population and generation capacity.[12] The second type of market operates under a decentralized "bilateral" system where

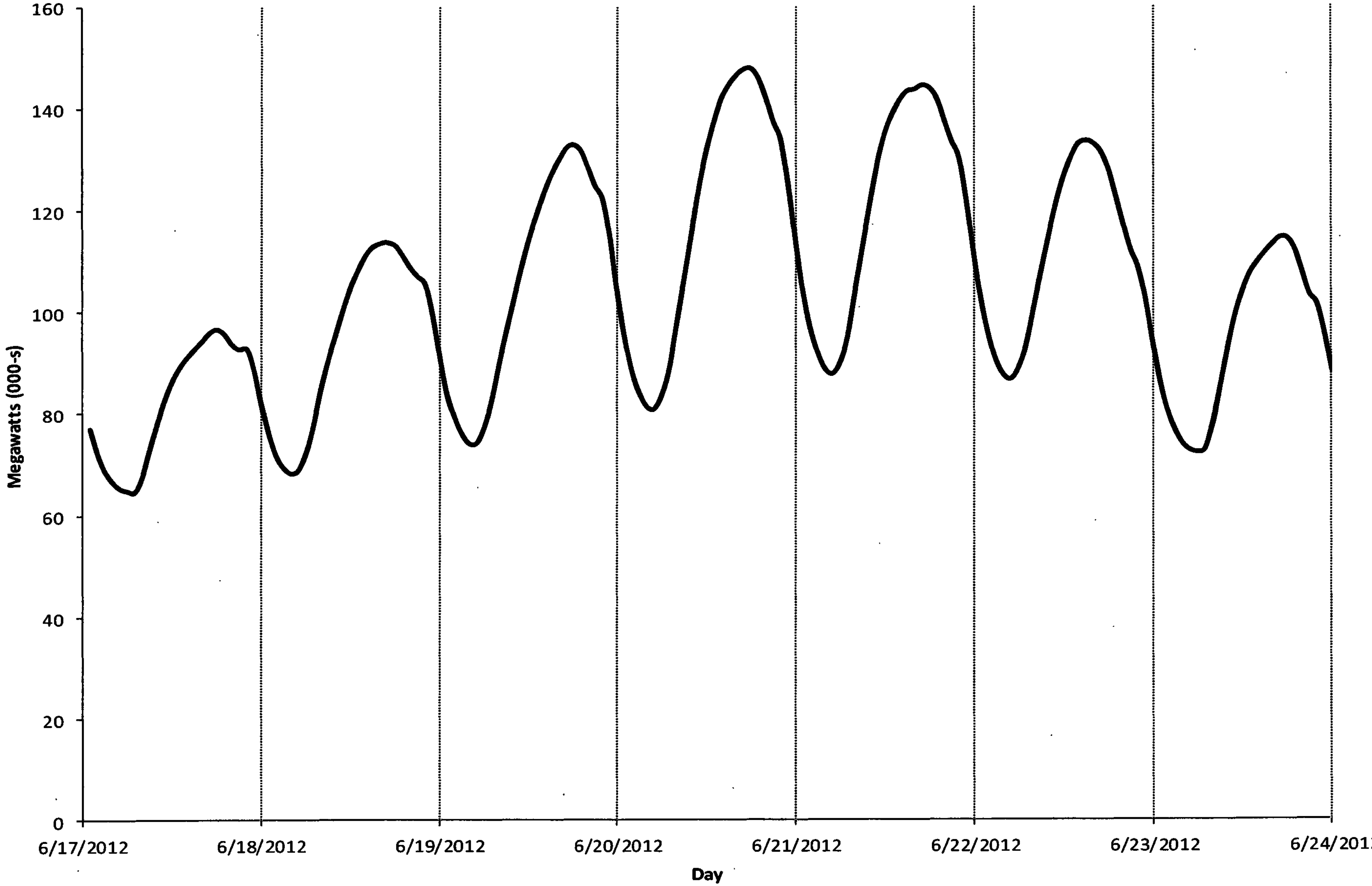
[11] RTO refers to a Regional Transmission Organization and ISO refers to an Independent System Operator.

[12] "RTO/ISO Information at a Glance," ISO/RTO Council, http://www.isorto.org/site/c.jhKQIZPBImE/b.2604469/k.9744/IRC_At_A_Glance.htm.

Figure 1

**ELECTRICITY DEMAND VARIES SUBSTANTIALLY THROUGHOUT THE DAY**

PJM Hourly Load

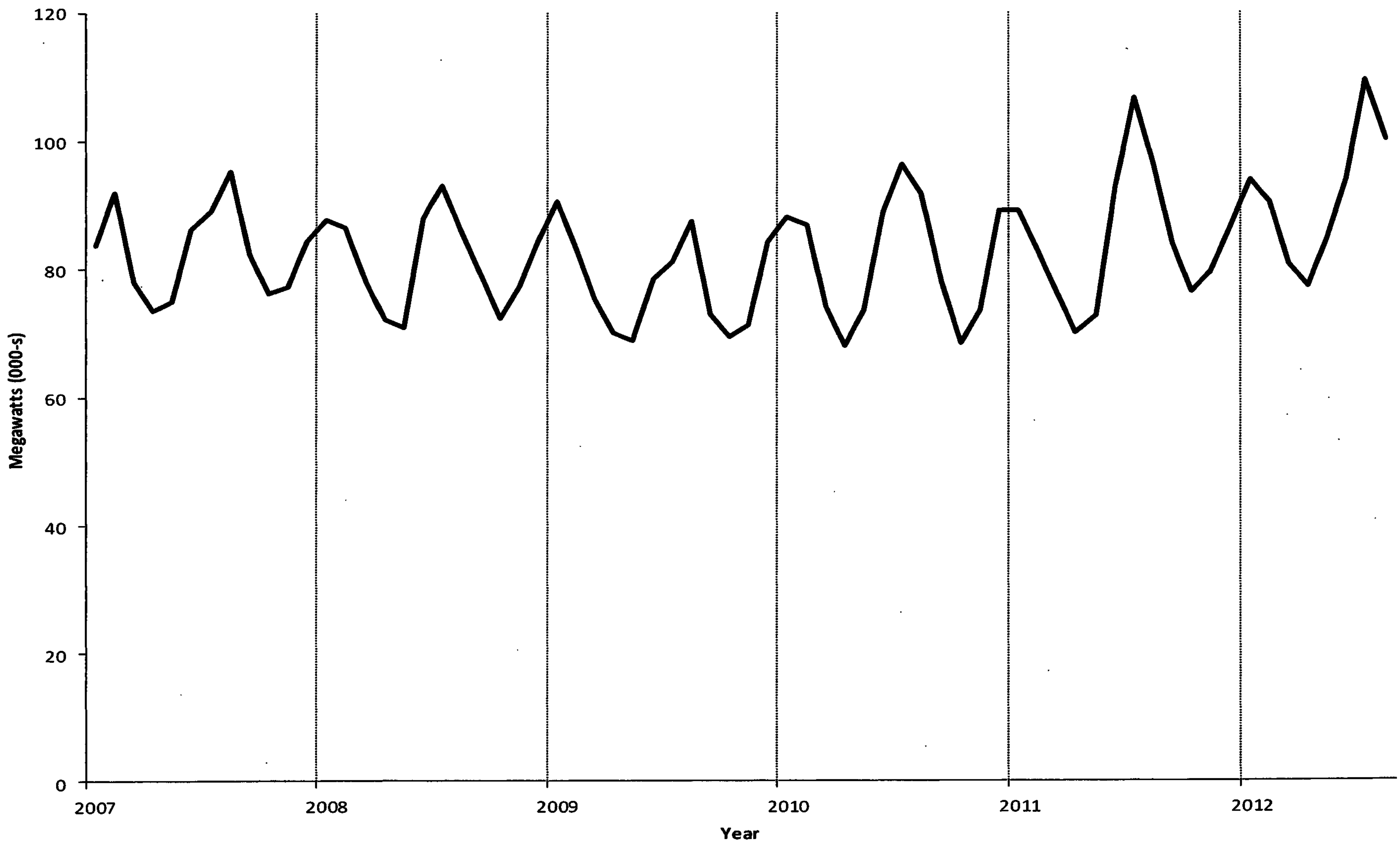



Note: Week of June 17th 2012. Vertical lines represent midnight for each respective day.
Source: Ventyx, ISO Total Load Dataset.

Figure 2

**ELECTRICITY DEMAND VARIES ACROSS SEASONS**

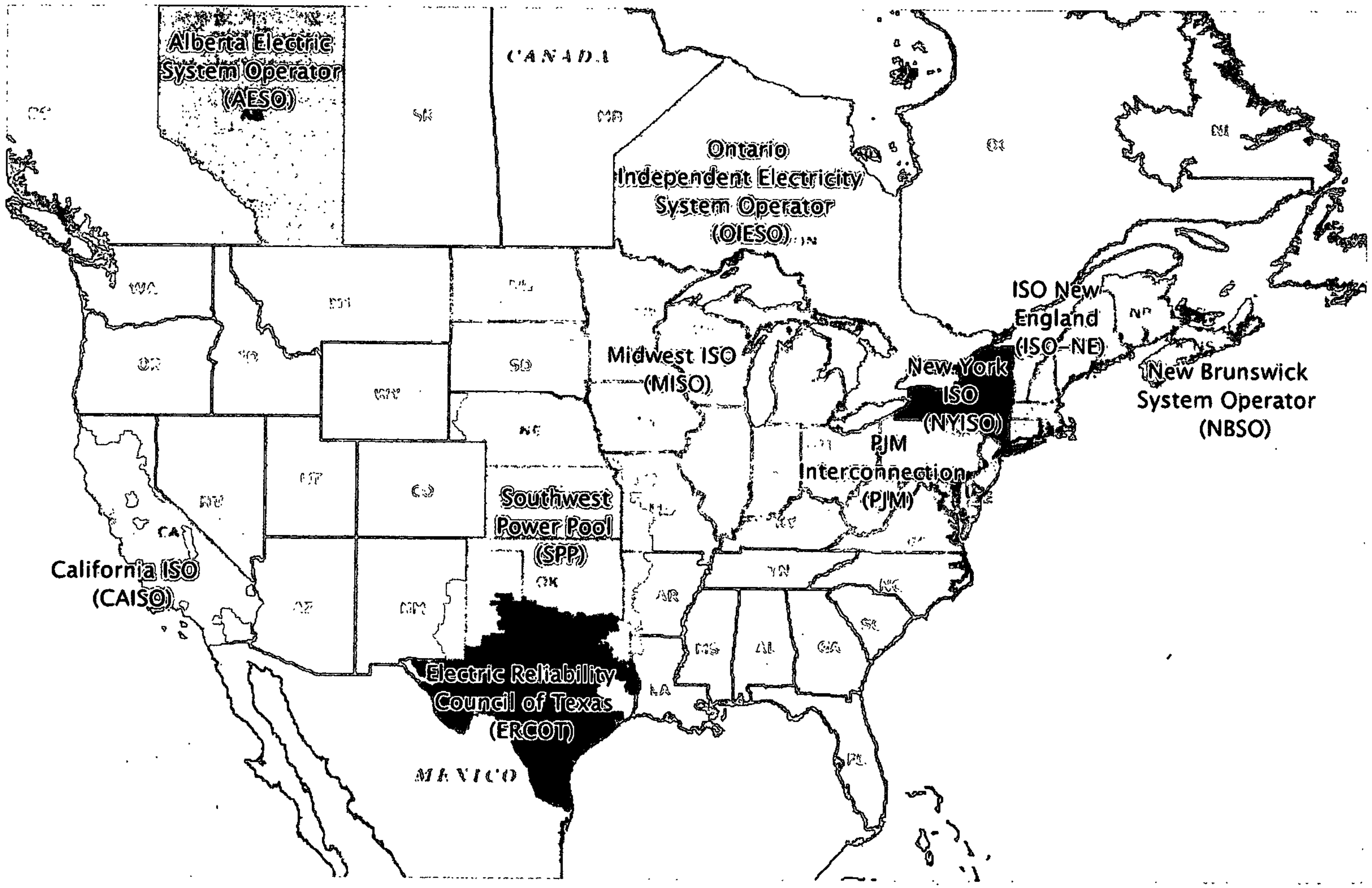
PJM Average Hourly Load by Month




Note: Vertical lines represent the first day of each respective year. Data spans from January 2007–August 2012.
Source: Ventyx, ISO Total Load Dataset.

Figure 3

## REGIONS OF INDEPENDENT SYSTEM OPERATORS




Note: Map current as of April 2012.
Source: FERC

independent power producers, marketers, and traditional utilities (typically vertically integrated), if granted wholesale market-based rate authority, sell wholesale power at market rates to potential purchasers, which will ultimately be delivered to end-users.[13]

Each RTO/ISO is "responsible for managing the high-voltage electric transmission assets of its member utilities and the wholesale electricity market(s) for the region it serves."[14] Every RTO/ISO operates a non-discriminatory market for the purchase and sale of electric energy on a real-time basis, in which a clearing price(s) is determined based on the prices offered into the market. Most also operate one or more additional markets for electric energy on a forward or day-ahead basis, as well as separate markets for generation capacity and for ancillary services. As part of their responsibility, they also manage the economic scheduling for power supply and load, including the dispatch of electric generation. And all have some form of market monitoring and mitigation to ensure the competitive operation of these markets. By nearly all metrics, RTO/ISO markets are found to be quite competitive: the markets show low levels of concentrations and market-

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[13] Federal power authorities also manage transmission and sell wholesale power. In particular, the Bonneville Power Authority sells wholesale power and manages much of the transmission system in the Pacific Northwest and adopts practices consistent with regulated bilateral markets.

[14] "Performance Metrics For Independent System Operators And Regional Transmission Organizations: A Report to Congress in Response to Recommendations of the United States Government Accountability Office," Federal Energy Regulatory Commission ("FERC"), Office of the Chairman, April 2011("ISO/RTO Report") at 6.

clearing prices are close to the corresponding marginal cost of the least efficient generation necessary to serve load.[15]

The bulk power system in the decentralized bilateral markets in the Southeast and Mountain regions outside the RTO/ISO regions are also structured and operated to ensure that wholesale sellers of power can compete under non-discriminatory terms.[16] Sellers of power in the wholesale power market may sell at market-based (rather than cost-based) rates only if they are found not to have, or to have adequately mitigated, horizontal and vertical market power.[17] Under those circumstances, utilities and other load-serving entities may obtain power from their own generation resources, or obtain lower-priced substitute power in the wholesale power market from alternative competing suppliers of power. Likewise, utilities may be able to sell power into competitive wholesale markets if they have available low-marginal-cost power that they can sell to other potential purchasers.

Competitive wholesale power markets permit an efficient use of lower-cost power inside and outside of the RTO/ISO regions. In centralized markets in the RTO/ISO regions, this results almost directly from ready access to power at transparent, market-clearing prices. Similarly, in bilateral markets outside of the RTO/ISO regions, state regulators have provided economic incentives, in terms of cost-saving or profit-sharing arrangements, for state-regulated vertically integrated

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15 ISO/RTO Report at 8-9.

16 FERC Orders 888 (April 24, 1996), 888-A (March 4, 1997), 888-B (November 25, 1997), 890 (February 16, 2007), and 890-A (December 28, 2007).

17 FERC Orders 697 (June 21, 2007), 697-A (April 21, 2008), and 890-B (June 23, 2008).

utilities to take advantage of market opportunities to displace higher-cost power with lower-cost power, even if lower-cost power must be procured in the bilateral market.[18] In either case, in locations where wholesale electricity markets have been found to be competitive, there arises the potential for meaningful effective indirect competition that can constrain rail rates for coal used in power generation to competitive levels.

## B. Competition from Natural Gas-Fired Generation

### *Traditional Roles of Natural Gas and Coal in Electric Power Generation*

Coal has long been the dominant fuel for electric power generation in the U.S. As shown in Figure 4, until the last few years, coal fueled roughly half of U.S. electricity generation. Since early 2009, however, the dominance of coal has significantly declined. In its place, natural gas generation, which at the beginning of the last decade provided only a third of the electric power provided by coal, has nearly caught up with coal's share of power generation.

Natural gas power generation has evolved since the 1990s. Natural gas had traditionally been used to fuel operationally flexible, but thermally inefficient, low-capital-cost combustion turbine ("CT") generators, which produced high-marginal-cost power needed to supply load only when demand was high.[19] Daily and seasonal variation in electricity demand (see Figures 1 and 2 above) leads to a rough

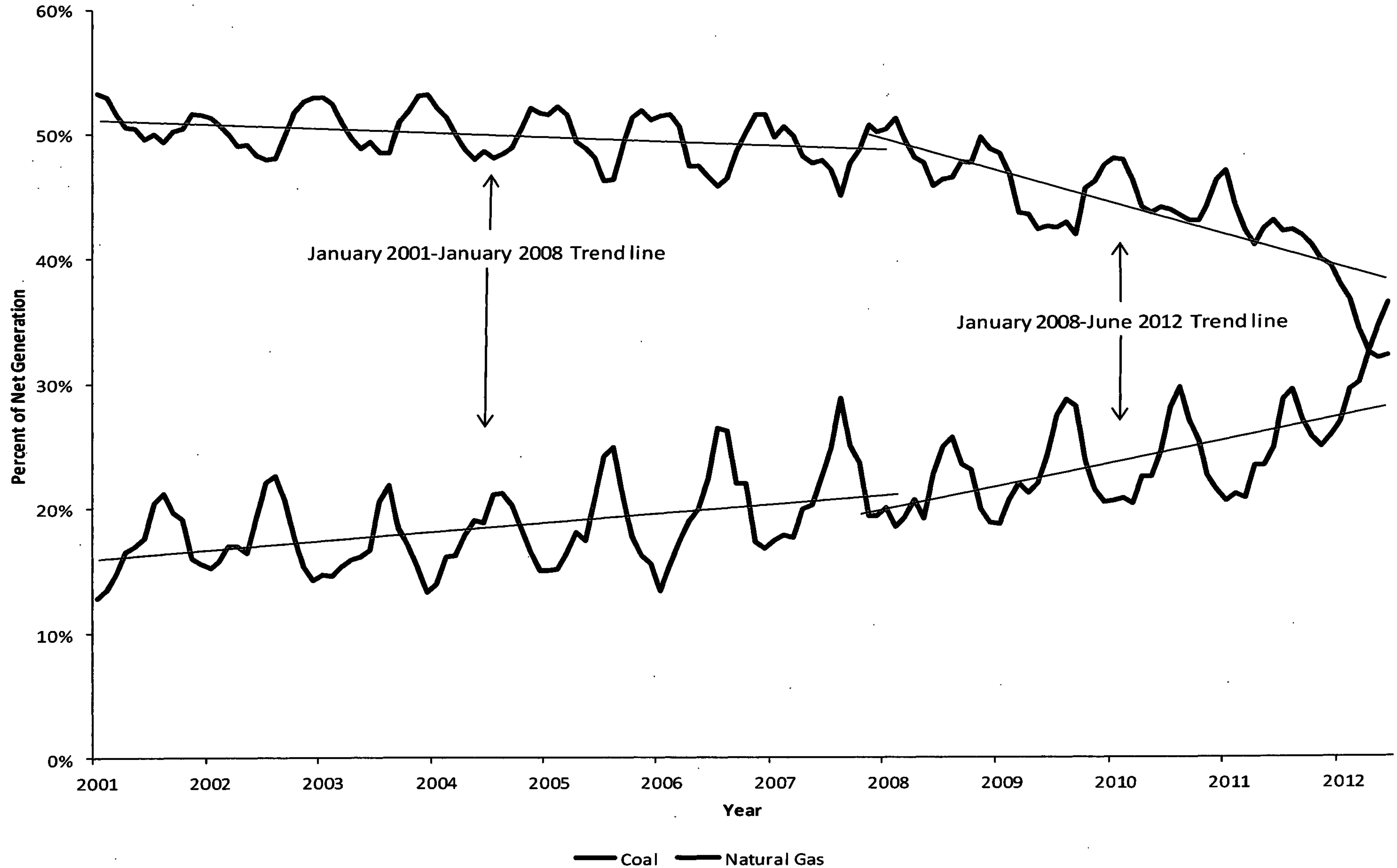
[18] See, for example, American Electric Power Company, Form 10-k, 2011, at 18-21.

[19] A combustion turbine operates similarly to a turbine jet engine, but where more of the energy in the fuel is converted into rotational motion to turn an electric generator.

Figure 4

## SHARE OF U.S. POWER GENERATION: COAL v. NATURAL GAS

January 2001–June 2012




Source: U.S. Energy Information Administration, Electricity Data Browser, Net Generation Dataset.[21]

characterization of generation resources as either *baseload* resources, that typically operate all or most of the time they are available to run; *peaking* resources, like many CTs, that tend to only operate during peak periods of demand; and *intermediate or mid-merit* resources, that operate much, but not all, of the time and give way to baseload resources during periods of off-peak demand. Nuclear, hydroelectric, and lower-marginal-cost coal-fired generation resources have historically provided baseload generation supply; some coal-fired generation resources and newer technology, more thermally efficient, natural gas-fired generation (discussed below) provided intermediate supply; and a low-capital-cost CT and other natural gas- and oil-fired technologies would provide the additional power above the baseload and mid-merit generation required to serve load during periods of high demand.[20]

***Sources of Change That Have Advanced Natural Gas-Fired Generation Relative to Coal-Fired Generation***

A number of factors have led to the advance of natural gas as a fuel for generation at the expense of coal, but I point out four major ones. First, technological improvements in natural gas-fired generation have greatly improved its thermodynamic efficiency, reflected in reduced heat rates. Modern combined-cycle gas turbines ("CCGTs"), almost always fired by natural gas, convert a greater portion of the energy in the "fuel" into electricity than any other technology

[20] Hydroelectric generators, wind, and other renewables have characteristics such that they may have relatively low marginal costs but limitations on their ability to generate electricity on a consistent basis.

deployed on a mass scale in electric power generation. A CCGT utilizes two stages to achieve this efficiency. In the first stage, natural gas is burned in a sophisticated, large scale combustion turbine; in the second stage, a heat recovery steam generator uses the turbine exhaust heat from the first stage to create steam which powers a steam turbine. Both the initial natural gas combustion and secondary steam turbines power electric generators. These natural gas-fired CCGTs ("NGCC") generators are substantially more fuel efficient, both under optimal conditions and in practice, than coal-fired generation.[21] A coal-fired generator requires 35% more energy in the form of fuel than does a NGCC generator to produce the same amount of electric energy.[22] And this advantage in efficiency is expected to increase as newer NGCC models are anticipated to have higher levels of fuel efficiency and more flexibility in following changes in load over time—an attribute that is increasingly valuable as intermittent renewable generation, such as wind power, becomes increasingly important. Advances in

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[21] Unger, D. and H.J. Herzog, Comparative Study on Energy R&D Performance: Gas Turbine Case Study, MIT Energy Laboratory Reports, August 1998; "Fast starts and flexibility: Let the gas turbine battle commence," *Power Engineering International*, June 1, 2012; and Kroemeke, Joergen "World Record at Irsching – high efficient Combined Cycle Power Plant," presentation, April 2012.

[22] Bartos, Frank J., "The Hunt For 60+% Thermal Efficiency," Control Engineering, August 1, 2008.

NGCC technology indicate natural gas-fired generation will become an even more effective competitor to coal-fired generation in the future.[23]

In addition to its high thermodynamic efficiency, NGCC generation technology has a number of additional advantages relative to coal-fired generation technology. The up-front capital cost per megawatt of capacity is lower for a NGCC generator than for a coal-fired generator, the time to build is shorter, and a NGCC-based power plant can be built in efficient scalable units of 150 to 450 megawatts.[24] NGCC-based power plants also typically can ramp output up and down in response to hourly changes in demand more easily and efficiently than coal-fired power plants. Through a variety of innovations, NGCC generation has seen a steady improvement in thermodynamic efficiency, flexibility, and reliability, making it increasingly competitive with coal-fired generation.

Second, the organization and operation of the markets for natural gas and wholesale power have improved greatly over the last two decades. Although highly

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23 Major NGCC manufacturers—GE, Siemens, Alstom, and Mitsubishi—have announced new products with greater than 60% fuel efficiency and enhanced flexibility from existing models. "Fast starts and flexibility: Let the gas turbine battle commence," Power Engineering International, January 6, 2011. General Electric recently announced $1.2 billion in orders for their FlexEfficiency 60 products, including two for Public Service of Colorado which will convert an existing coal-fired generation facility into an NGCC. "GE Launches Breakthrough Power Generation Portfolio with Record Efficiency and Flexibility with Natural Gas; Announces Nearly $1.2 Billion in New Orders," General Electric press release, September 26, 2012. http://www.genewscenter.com/News/GE-Launches-Breakthrough-Power-Generation-Portfolio-with-Record-Efficiency-and-Flexibility-with-Natural-Gas-Announces-Nearly-1-2-Billion-in-New-Orders-3b54.aspx, accessed October 1, 2012. Florida Power and Light, for example, is replacing the Cape Canaveral and Riviera steam generation facilities with state-of-the-art Siemens H-class NGCCs with 2,500 MW total capacity. These plants will consume a third less fuel per megawatt-hour than the replaced facilities. www.fpl.com, accessed October 2, 2012.

24 One megawatt of power generation, producing constantly for a year, generates energy equal to that used by roughly 750 to 1,000 homes.

regulated, both wholesale power and natural gas markets have developed so that buyers and sellers at the wholesale level can effectively engage in sophisticated and competitive market transactions. In particular, independent power producers and other wholesale electric power producers can buy natural gas and buy and sell wholesale electric power in competitive markets. As natural gas and electric power are both economically significant, fungible commodities, active trading in physical spot and term transactions, and in financial futures, options, and derivatives, has developed to support these markets. These developments have made it possible for incumbents and new entrants to respond quickly and efficiently to market signals regarding investment and production in both the bulk power system and the natural gas sector (e.g., production, storage, and transportation).

Third, a suite of existing, proposed, and likely to be proposed environmental regulations from the U.S. Environmental Protection Agency ("EPA") has further tipped the economic balance in favor of natural gas for use in electric power generation. Burning natural gas for electric power generation emits fewer air pollutants than does burning coal, including the amount of the primary greenhouse gas ("GHG"), $CO_2$, per unit of electricity produced; and the increasing efficiency of natural-gas fired generation resources should further reduce emission of pollutants per unit of electricity produced by these newer resources. While the uncertainties of politics, litigation, and judicial and regulatory review make future implementation of the full suite of EPA regulations uncertain, the regulations are nonetheless expected to require substantial investment in pollution abatement for many coal-fired electric generation facilities, and owners of some of these facilities may choose to close them rather than incur these costs. First, nitrogen and sulfur oxide emissions from power plants in over twenty eastern states are to be reduced to improve downwind air quality in the eastern U.S. While more stringent rules have recently been remanded by the courts, previously promulgated regulations will go into effect in 2015. Second, and perhaps more significantly, rules restricting mercury (and other toxic) emissions require the installation of "maximum achievable control technology" or "MACT." Unlike programs with tradeable permits, the MACT regulations will require the addition of new pollution control equipment to most existing coal-fired generation resources. Third, proposed GHG rules impose limits on $CO_2$ emissions for new generation that will in effect make it difficult to build new coal-fired generation in the future without spending money on carbon capture and sequestration technology (and some form of GHG rules may be imposed on existing coal-fired resources as well). Finally, the EPA is considering yet-to-be published regulations covering the proper disposal of ash left over from the burning of coal in power plants. None of these environmental regulations impose a significant burden on most existing or new natural gas-fired generation, but may impose large costs on many coal-fired generators.[25]

Fourth and finally, the shale gas revolution has radically altered current market conditions and future prospects for natural gas supply. Technological

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25 James E. McCarthy and Claudia Copeland, "EPA's Regulation of Coal-Fired Power: Is a 'Train Wreck' Coming?" Congressional Research Service, August 8, 2011.

improvements in horizontal drilling and hydraulic fracturing have made it possible to develop and produce oil and natural gas—referred to as "shale gas"—from large hydrocarbon-bearing shale formations throughout the U.S. and the globe. Since 2005, the effects of this new technology have begun to be felt in the supply and attractiveness of natural gas to electric power producers. The result has been a large increase in domestic natural gas production and inventories, and a decline in the price of natural gas, from an average of $7.11 per million Btu ("MMBtu") delivered to gas-fired generation facilities in 2007, to $3.10 per MMBtu in the first half of 2012.[26] As the per-unit energy cost of natural gas falls, and has fallen, relative to the equivalent per-unit energy cost of delivered coal, natural gas-fired generation has become relatively more economically attractive than coal-fired generation. Because this fundamental shift in the natural gas market has such a significant impact on indirect competition in the market for rail rates on shipments of coal, I take some time below to explain the current and future impact of the shale gas revolution on natural gas markets.

### *Production and Consumption of Natural Gas*

The shale gas revolution started in 1998 with the first commercially successful well that applied two technologies—horizontal drilling and hydraulic fracturing—that could be used widely to produce natural gas from shale. The adaptation of these technologies has added vast volumes of previously inaccessible

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[26] U.S. Energy Information Administration, *Monthly Energy Review*, September 2012, at Table 9.10.

natural gas to the potential gas supply of the U.S. Figure 5 shows the total U.S. natural gas production and the shale gas component. In 2005, shale gas accounted for only 4% of U.S. production. By 2011, shale gas accounted for 30% of U.S. production, and production was growing at a rate of 45% a year.

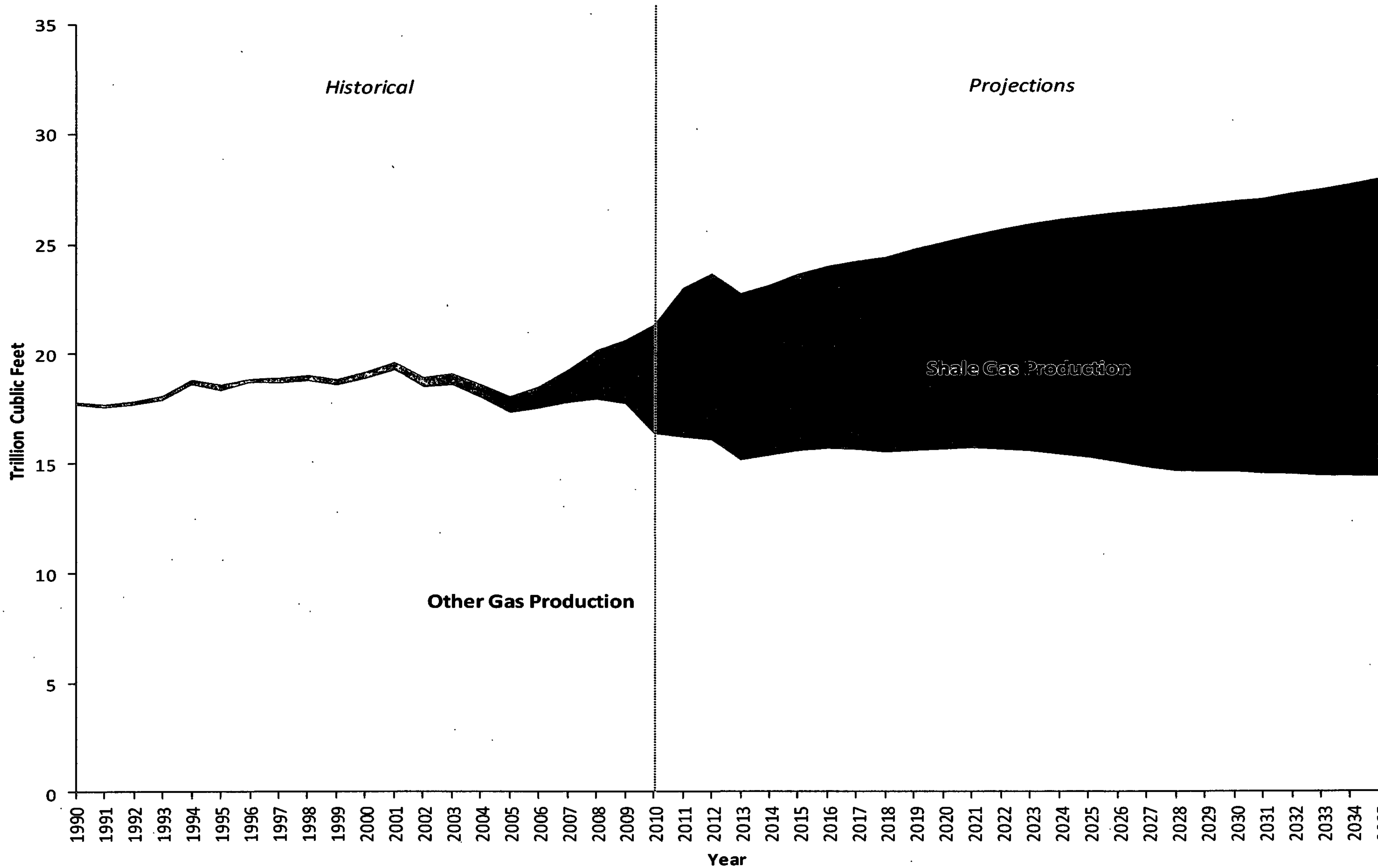
Productive shale gas deposits are located throughout the U.S., with large deposits in areas that in recent decades were not major producers of oil and natural gas. (See Figure 6.) Production of shale gas so far has come primarily from traditional producing areas, such as Texas and Louisiana, with existing infrastructure, some of which has been expanded and adapted for the new production. But shale gas production activity is rapidly developing in the Northeast, which has previously incurred the costs of transporting natural gas long distances. For example, in 2006, 27 gas wells were drilled in Pennsylvania into the Marcellus shale. Drilling activity in the Marcellus shale in Pennsylvania has nearly tripled each year; over 2,000 wells were drilled in 2010. The expansion into such non-traditional producing regions allows electric power resources to obtain natural gas without incurring the cost of long-distance transportation, accelerating this shift from coal-fired to natural gas-fired generation in the eastern U.S., which has historically utilized Appalachian coal.

The increasing supply of natural gas in the U.S., driven by shale gas production, has led to lower prices and increased consumption. As seen in Figure 7, since mid-2009, the standard reference price of natural gas (at the Henry Hub in

Figure 5

**U.S. PRODUCTION OF NATURAL GAS**

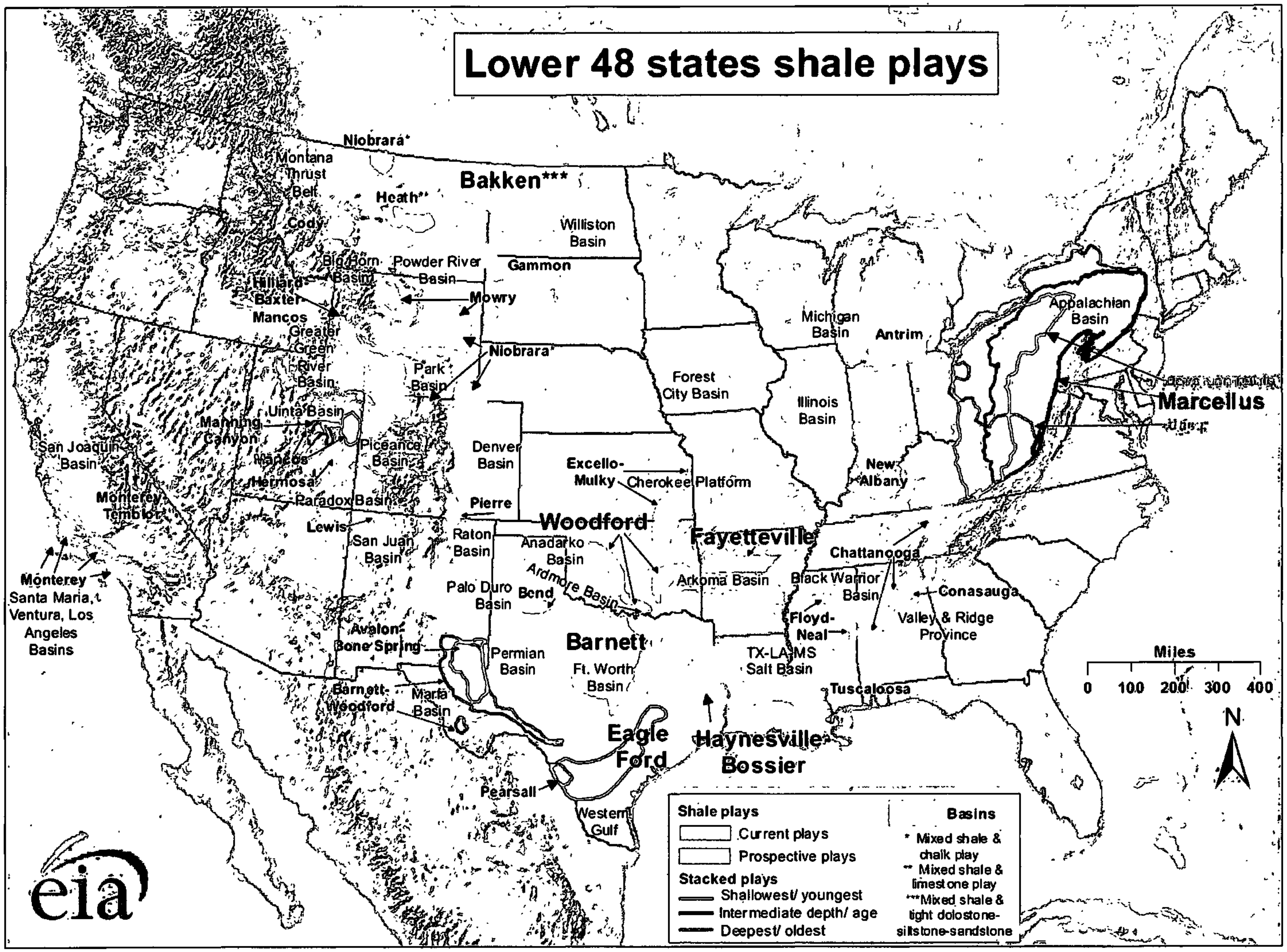
1990-2035




Source: U.S. Energy Information Administration, Annual Energy Outlook 2012.

Figure 6

**MAJOR SHALE GAS AREAS**

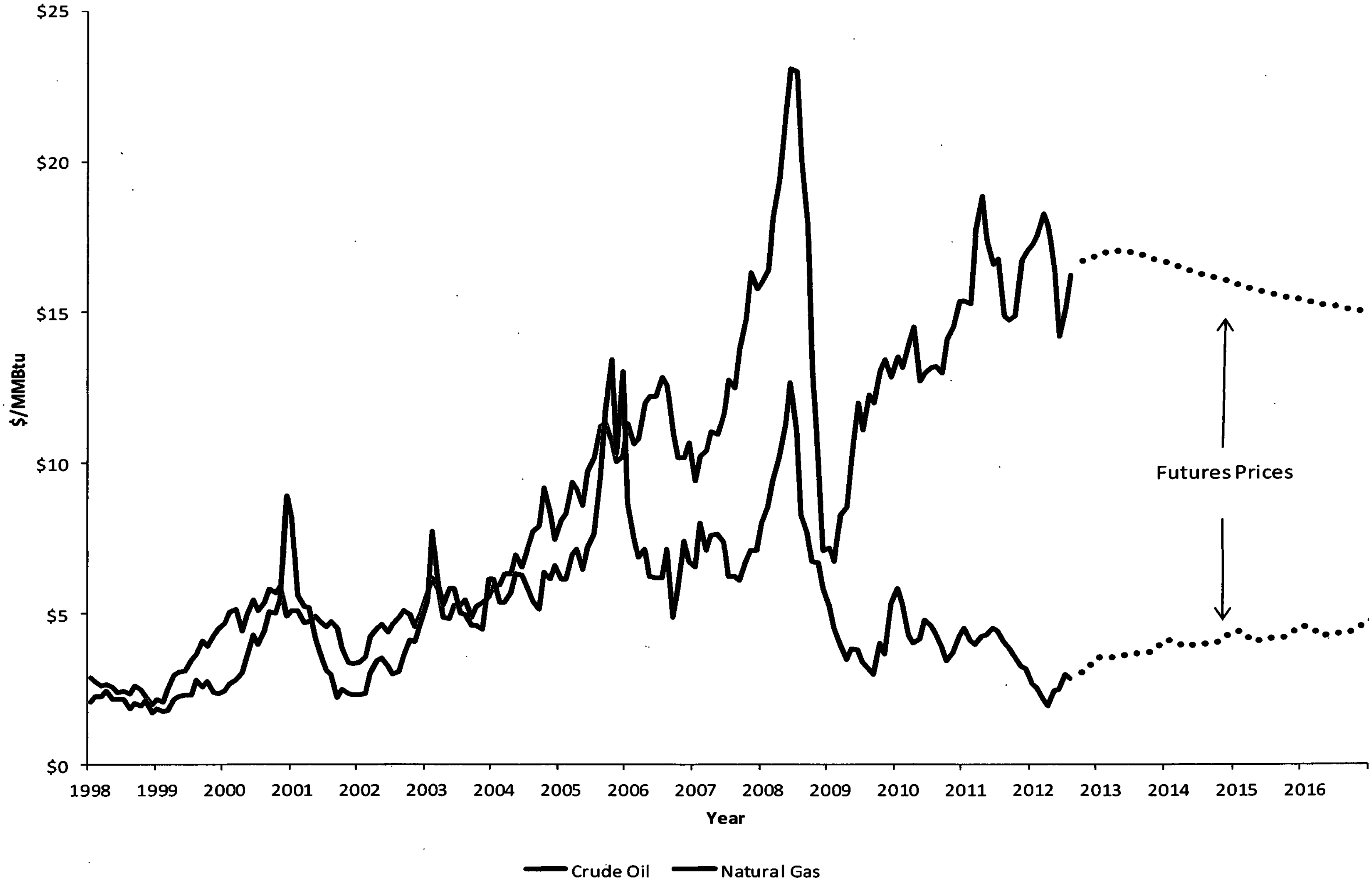



Source: U.S. Energy Information Administration

Figure 7

## U.S. NATURAL GAS PRICES NO LONGER TRACK CRUDE OIL PRICES

January 1998–December 2016




Note: Average monthly price shown. Price of Crude Oil converted to $/MMBtu. 5.8 million Btu per barrel Crude Oil. Gas and Crude Oil futures prices are Henry Hub Natural Gas futures and Light Sweet Crude Oil futures, respectively. Contract futures prices from September 12, 2012 trade date.
Source: U.S. Energy Information Administration. Ventyx, NYMEX and ClearPort Futures Dataset.

Louisiana) has fluctuated between \$6 per MMBtu to less than \$2 per MMBtu in April 2012. Figure 8 shows the total U.S. consumption of natural gas, and the amount consumed by the electric generation sector. Despite relatively stable total electricity demand (it has increased at a rate of less than 1% per year since 2007), the consumption of natural gas for electricity averaged an annual 2.5% rate of growth since 2007. In response to low natural gas prices (relative to prices for delivered coal) in the first half of 2012, the amount of natural gas burned in the electricity sector was more than 30% higher than for the corresponding period in 2011.

*Natural Gas Prices*

U.S. natural gas prices depend on demand and supply conditions in North America, with only limited influence from overseas markets (due to the relatively high cost of transporting natural gas by ship.) Crude oil trades globally, and except for physical and political constraints, crude oil prices reflect global demand and supply conditions.[27] Despite the difference in geographic scope, U.S. natural gas and crude oil market prices historically have tended to move together, with crude oil selling at one to two times the reference price of natural gas when expressed on an

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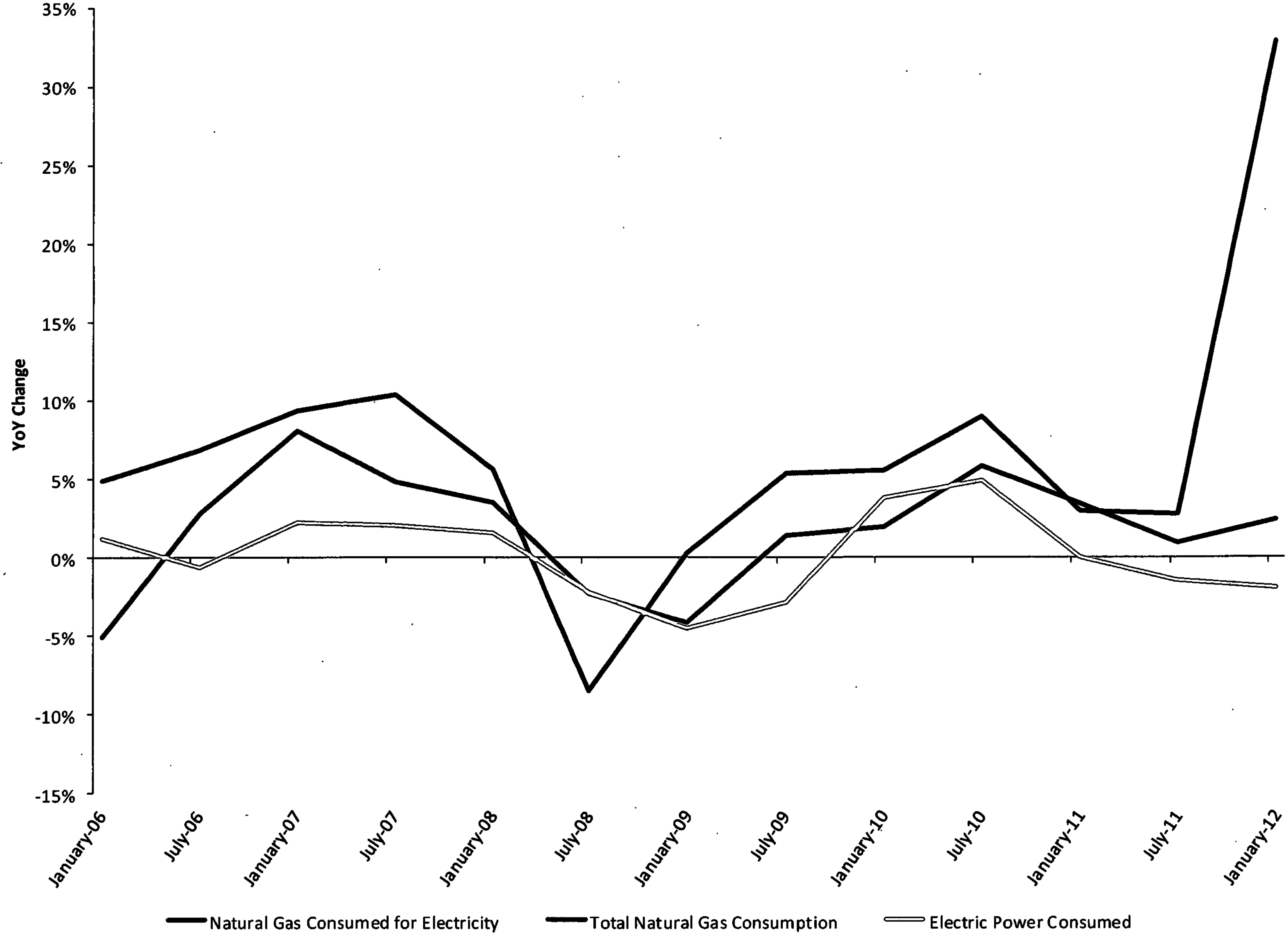
27 The U.S. reference price, in dollars per barrel, is for Light Sweet crude oil at Cushing Oklahoma, as defined in the New York Mercantile Exchange futures contract. This is often referred to as the West Texas Intermediate, or "WTI," price. The WTI price since early 2011 has been trading at a discount to the international reference (Brent crude oil) price due to changing patterns of crude production in the U.S. leading to pipeline constraints. This has been brought about, in part, by new sources of oil supply from oil-bearing shale formations. See, for example, U.S. Energy Information Administration, "Short-Term Energy Outlook Supplement: Brent Crude Oil Spot Price Forecast," July 10, 2012.

Figure 8

## GROWTH IN NATURAL GAS CONSUMED FOR ELECTRIC POWER PRODUCTION

Growth Rate from Previous Year 2005-2012




Note: Percentages show changes from the corresponding period in the previous year. Original gas consumption is recorded in thousand MMcF. Original electricity consumption is recorded in million kilowatt-hours.
Source: U.S. Energy Information Administration, Annual Energy Outlook 2012.

energy-equivalent basis (e.g., dollars per MMBtu).[28] (See Figure 7.) But their prices no longer move in tandem. Starting in 2008, as crude oil prices spiked to over $145 per barrel ($25/MMBtu), the price of natural gas has not followed. (See Figure 9.) In spite of the financial crash and recession starting in 2008, crude oil prices have stayed relatively high—fluctuating most of the time between $70 and $120 per barrel—but U.S. natural gas prices have not. As shown in Figure 7, natural gas prices have fallen to generally between $2 and $4 per MMBtu; since mid-2009, crude oil has been priced at 2.3 to 9.2 times that of U.S. natural gas on an energy-equivalent ($/MMBtu) basis.[29]

### *U.S. Natural Gas Resources: The Future*

The shale gas revolution in the U.S. has just begun. The new commercial access to shale-based natural gas has reversed a twenty-year period of flat or declining U.S. natural gas reserves. Figure 10 shows that proved natural gas reserves increased by 45% from 2006 to 2010. Proved reserves are those that can be produced in the future with high certainty based on known geology and engineering under existing economics and technology.[30] In 2010, proved reserves were equal to fifteen years of production.

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[28] The reference price, in dollars per MMBtu ($/MMBtu), for natural gas in the U.S. is at the Henry Hub in southern Louisiana. As in rail transportation of coal, transportation of natural gas from producing areas can add significantly to the delivered cost even for large users such as electric power plants.

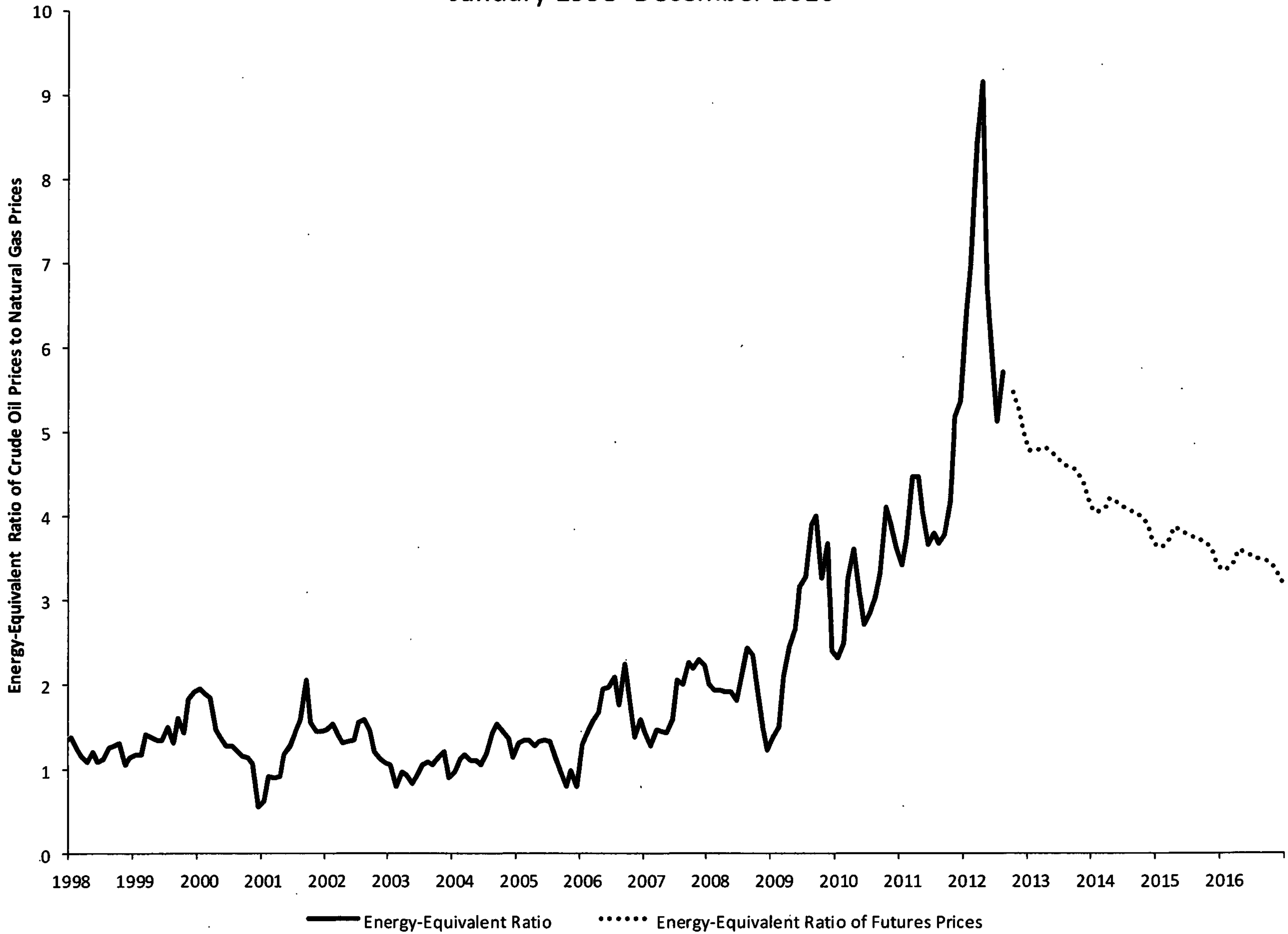
[29] Natural gas prices in Japan and Europe have remained such that crude oil is one to two times the price of natural gas. World Bank Commodity Price Data (Pink Sheets).

[30] U.S. Energy Information Administration, *Annual Energy Outlook 2012* ("AEO 2012") at 56.

Figure 9

## CRUDE OIL PRICES HAVE INCREASED RELATIVE TO NATURAL GAS PRICES

January 1998–December 2016




Note: Figure 9 shows a ratio of average monthly prices. Price of Crude Oil converted to $/MMBtu. 5.8 million Btu per barrel Crude Oil. Gas and Crude Oil futures prices are Henry Hub Natural Gas futures and Light Sweet Crude Oil futures, respectively. Contract futures prices from September 12, 2012 trade date.
Source: U.S. Energy Information Administration. Ventyx, NYMEX and ClearPort Futures Dataset.

Figure 10

**U.S. NATURAL GAS PROVEN RESERVES**

2006-2010

| | Shale (TcF) | Other (TcF) | Total (TcF) |
|---|---|---|---|
| 2006 | 14 | 206 | 220 |
| 2007 | 23 | 224 | 248 |
| 2008 | 34 | 221 | 255 |
| 2009 | 61 | 223 | 284 |
| 2010 | 97 | 220 | 318 |

Source: U.S. Energy Information Administration, U.S. Crude Oil, Natural Gas, and NGL liquids Proved Reserves Dataset, Released Data August 1, 2012.

While the measure of proved reserves is utilized for financial reporting, a common measure of the long-term viability of U.S. domestic crude oil and natural gas as an energy source is the remaining technically recoverable resource ("TRR").[31] The TRR consists of proved reserves plus "additional volumes estimated to be technically recoverable without consideration of economics or operating conditions, based on the application of current technology."[32] These estimates are subject to substantial uncertainty, but with additional experience in production, the evolution of technology, and development of new information on potential resources, estimates of TRR are re-determined. Depending on future economic circumstances and advances in technology these TRRs can turn into proved reserves and then be produced.

The shale gas revolution has dramatically changed the evaluation of total TRR. Figure 11 shows the changing estimates of the TRR from a variety of industry and government organizations by the year the estimate was made. As more information has been gained, the trend is upward, with most of the increase due to shale (and other unconventional) gas resources. By 2010 and 2011, the TRR estimates ran to roughly 2,000 trillion cubic feet ("Tcf"). With 21.6 Tcf of dry production in 2010 (the base year of information when the most recent estimates were made), the TRR estimates amount to nearly 100 years of current U.S. production.

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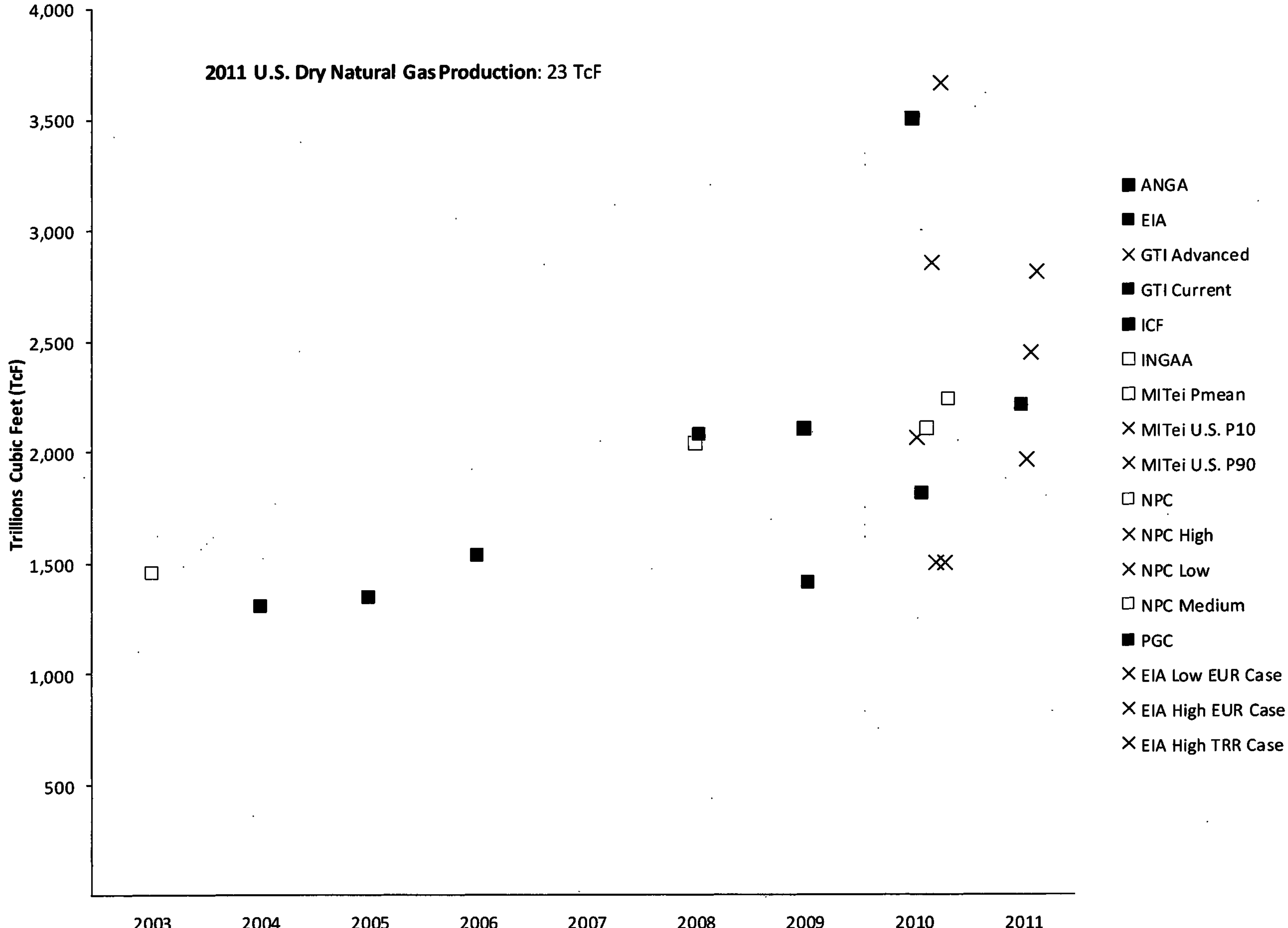
31 Ibid.
32 Ibid.

Figure 11

# ESTIMATE OF TECHNICALLY RECOVERABLE U.S. NATURAL GAS RESOURCES BY YEAR IN WHICH ESTIMATE IS CREATED

2003-2010




Note: Shows estimates of technically recoverable reserves using a number of different methods. ANGA is the America's Natural Gas Alliance; the EIA is the Energy Information Administration; GTI is the Gas Technology Institute; ICF is ICF International; INGAA stands for the Interstate Natural Gas; Association of America; MITei is the Energy Institute at Massachusetts Institute of Technology; NPC is the National Petroleum Council; PGC stands for the Potential Gas Committee.

Source: U.S. Energy Information Administration; National Petroleum Council, "Crude Oil and Natural Gas Resources and Supply," Table 1-16.

Nearly all estimates, however, suggest that natural gas production will increase in the near future and over the next couple of decades. Figure 12 shows estimated production levels in 2015 and 2025, and indicates that the U.S. Energy Information Administration ("EIA") expects production will continue to grow above current levels. None of these estimates took into account the substantial increase in production and coal-to-gas switching in the electricity sector that occurred in 2011 and 2012. There is little reason to doubt that natural gas will be widely available and play a larger role as a fuel for power generation for years to come.

### *U.S. Natural Gas Prices: The Future*

Natural gas prices so far in 2012 have been historically low, with the Henry Hub price under $3/MMBtu and dipping below $2/MMBtu at one point. (See Figure 7 above for prices.) Since the beginning of 2009, however, the natural gas reference price has been below $5/MMBtu for all but a handful of weeks. At these levels, natural gas is an effective competitor in many circumstances to coal for power production.

While there is a degree of consensus about the future for natural gas production, the future of natural gas prices is less clear. Energy commodity prices, crude oil and natural gas in particular, have swung widely and quickly in the past; there is little reason to believe the future will be different in this regard. While prices may be difficult to predict at any point in time, the supply of natural gas and ultimately the price toward which it tends to move over longer periods of time are determined by the marginal cost of production. Estimates of the future long-term

Figure 12

## PROJECTION OF U.S. NATURAL GAS PRODUCTION

2015 and 2025

| Source and Case | | 2015 (TcF) | 2025 (TcF) |
|---|---|---|---|
| EIA Cases | *Reference* | 23.7 | 26.3 |
| | *High EUR* | 24.4 | 27.8 |
| | *Low EUR* | 22.8 | 24.3 |
| | *High TRR* | 26.5 | 30.9 |
| **IHSGI** | | 23.8 | 27.2 |
| **EVA** | | 23.8 | 26.7 |
| **Deloitte** | | 24.5 | 27.3 |
| **Seer** | | 23.7 | 25.9 |
| **ExxonMobil** | | 24.0 | 27.0 |
| **INFORUM** | | 24.3 | 27.6 |

**Note:** 2010 dry natural gas production = 21.6 TcF

Note: Projections developed prior to availability of 2011 data. The High and Low EUR and the High TRR estimates are calculated by the EIA to examine the uncertainty associated with estimating technically recoverable natural gas resources. These estimates adjust the estimated ultimate recovery (EUR) per well and the well spacing assumed in the reference case.
Source: U.S. Energy Information Administration, Annual Energy Outlook 2012.

marginal cost of production out to 2020 vary over a range of roughly $3/MMBtu to $7/MMBtu.[33] Translating this into prices, the EIA, for example, projects Henry Hub prices in its base case through 2020 of around $4.50/MMBtu (in real 2010 dollars), with a range of prices in different cases ranging between $3 and $6/MMBtu both at the Henry Hub and delivered to the electric power producers.[34] While future prices are necessarily uncertain, anticipated prices are in a range that makes natural gas a competitive alternative to coal used in power generation.

### *Observed Effects of the Advance of Natural Gas-Fired Generation Relative to Coal-Fired Generation*

The factors discussed above are reflected in the observed changing roles of coal and natural gas in power generation. Changes in electricity and natural gas markets and advances in NGCC technology led to the construction in the 2000s of many new natural gas-fired generation facilities, with correspondingly large amounts of new relatively more efficient generation capacity. (See Figure 13.) The additional natural gas-fired generation output entering the wholesale power markets is predominantly coming from these already existing efficient NGCC generation resources.[35]

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[33] International Energy Agency, *Golden Rules for a Golden Age of Gas: World Energy Outlook Special Report on Unconventional Gas*, 2012, at 72.

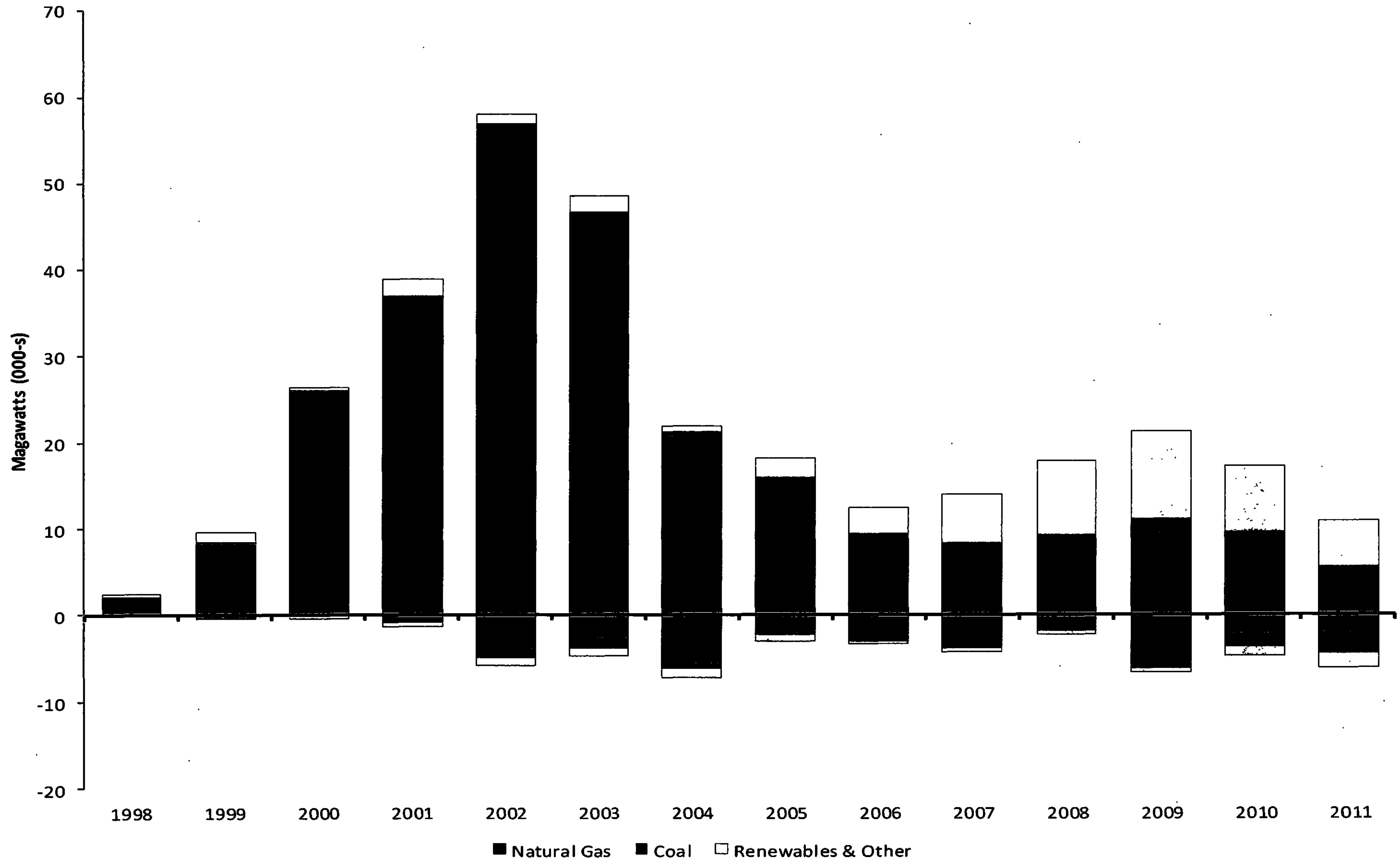
[34] AEO 2012, Table 13, Natural Gas Supply, Disposition, and Prices, multiple cases.

[35] A substantial amount of lower-cost, less-efficient, simple-cycle CT generation was also added. While less efficient than CCGT generation technology, these newer CT generators benefited from some of the same technological improvements and thus were also more fuel efficient than pre-existing natural gas-fired peaking units.

Figure 13

**ELECTRIC GENERATION CAPACITY ADDITIONS AND RETIREMENTS BY FUEL SOURCE**

1998-2010




Note: EIA capacity retirements data are unavailable for 1998. Positive megawatts indicate capacity additions, and negative megawatts indicate capacity retirements. Electric generation capacity addition by Natural Gas for years 1998-2010 contains nominal amounts of addition by Oil. 2011 is produced from early release data that have not yet validated. The early release data Includes approximately 20,000 operating and proposed generators. A small number are excluded pending data validation.
Source: U.S. Energy Information Administration, Annual Energy Outlook 2011. U.S. Energy Information Administration, Utility Plants 1999. Energy Information. U.S. Energy Information Administration. Form EIA – 860. "Annual Electric Generator Report."

Figure 14 shows the average monthly heat rate by month for all coal-fired and natural gas-fired electric generation output since 1998. (As discussed previously, the heat rate measures the energy in a fuel that is required to create one kWh of electrical energy.) Up until the early 2000s, the heat rates for natural gas-fired and coal-fired generation output were similar, meaning that they produced electricity with similar efficiency. As the large volume of newer, more efficient NGCC capacity was added to the then-existing fleet of less-efficient natural gas-fired generation, the average efficiency of natural gas-fired generation output increased. (This corresponds to the heat rate falling in Figure 14.) And since the more efficient NGCC plants run more often than less fuel efficient natural gas-fired CTs, this further improves the average fuel efficiency of natural gas-fired electric power production.[36]

The difference in fuel efficiency holds even when looking at coal-fired and NGCC-based power plants that have produced the greatest amount of generation output. A comparison of twenty coal-fired and natural gas-fired power plants, respectively, with the largest electric energy production in 2010 shows that the coal-fired power plants had an average heat rate of over 10,000 Btu per kWh compared to under 7,350 Btu per kWh for the NGCC plants—a fuel efficiency advantage of more than 35% for the NGCC plants.

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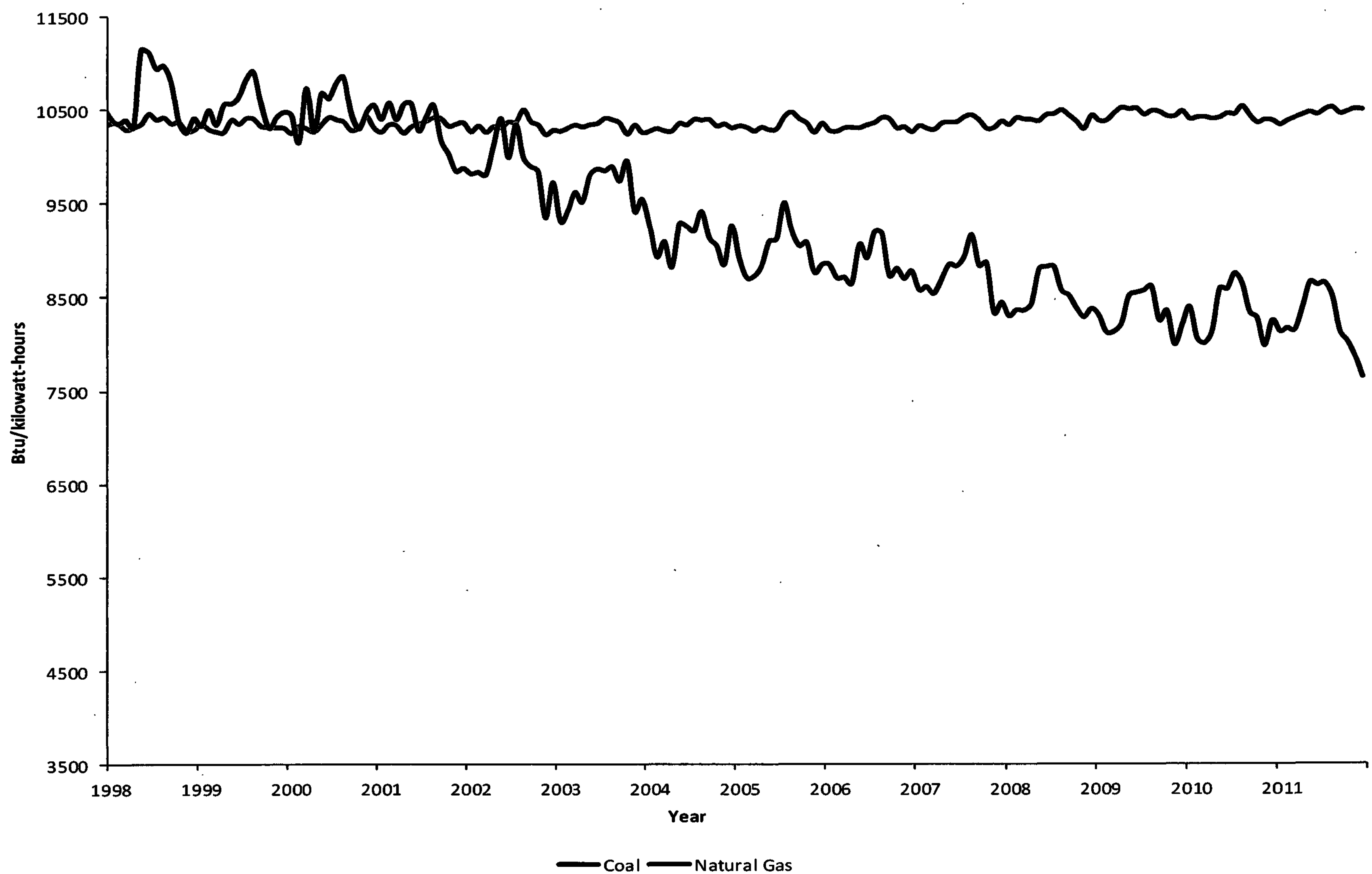
[36] The roller coaster variation reflects reduced gas turbine efficiency in hotter weather and the inclusion of less efficient peaking generation during peak summer and winter periods.

Figure 14

## AVERAGE ELECTRIC GENERATION HEAT RATE BY FUEL TYPE

January 1998–August 2011




Note: Heat rate is based upon plant operation, maintenance and fuel costs reported in the FERC Form 1, EIA-412 or RUS-12.
Source: Ventyx, Unit Generation and Emissions Dataset.

Coal-fired electric generation has always had, at least until the late 2000s, one main advantage over natural gas-fired generation—the delivered cost of the coal to the plant was far less than that for natural gas when expressed an energy equivalent (dollars per Btu) basis. Figure 15 shows that the average delivered cost of natural gas at the power plant is, at least for now, still greater than the average delivered cost for coal. Since mid-2008, however, the gap has narrowed dramatically. In 2012, for the five months in which data is available, the average delivered cost of coal was $2.42/MMBtu compared to natural gas at $3.10/MMBtu. While coal thus maintained a 28% average delivered cost advantage, that advantage no longer translates into a lower marginal cost of generation once the greater efficiency of natural gas-fired generation is accounted for. Adjusting the available 2012 fuel prices for the difference in the relative fuel efficiency of coal-fired and gas-fired generation (based on the average efficiency of twenty largest power producers utilizing each fuel), the natural gas required to produce a kilowatt-hour of electricity costs 8% *less* than the equivalent amount of coal. For the first part of 2012, the cost advantage of coal for electric power generation had, on average, disappeared.

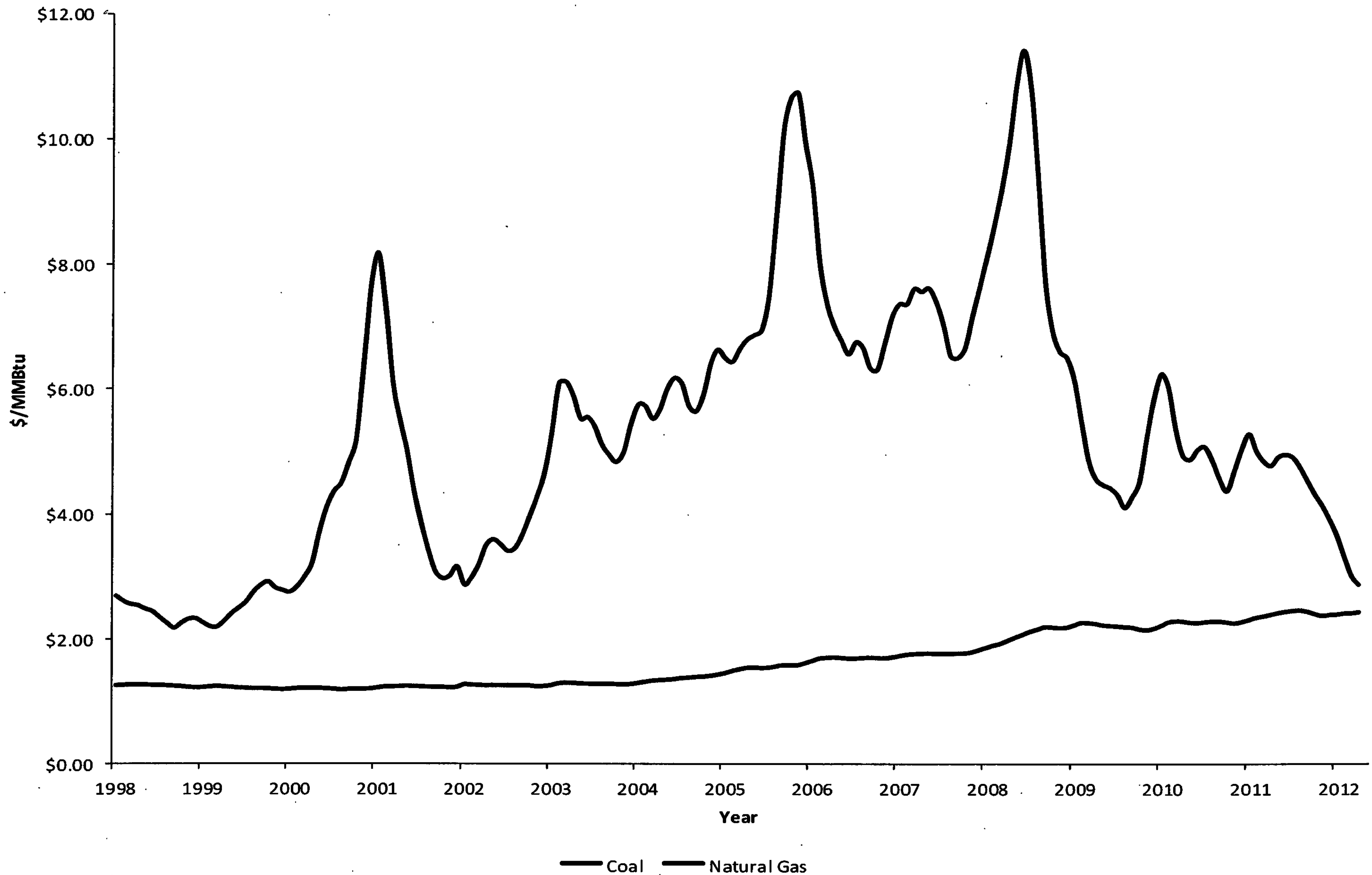
The impact of these changes is not uniform either across or within the wholesale power markets in the U.S. The price of natural gas and the price of delivered coal vary across regions. While some degree of substitution of natural gas for coal in power generation has occurred in nearly all regions of the U.S., at least through the retirement or planned retirements of coal-fired resources along with the

Figure 15

**COST OF DELIVERED FUEL TO THE ELECTRIC POWER INDUSTRY**

**NATURAL GAS v. COAL**

January 1998–May 2012




Note: Figure 15 shows a three Month centered moving average price. Dollars per MMBtu includes taxes.
Source: U.S. Energy Information Administration, August 2012 Monthly Energy Review.

construction of new natural gas-fired plants, the effect is hardly uniform. In locations with efficient coal-fired generation facilities that do not require extensive additional investments in environmental controls and that have access to low-cost delivered coal, the extent of competition from natural-gas fired generation may be muted. In contrast, locations characterized by older coal-fired generation facilities utilizing more expensive coal, subject to more stringent environmental restrictions, or in which local production of natural gas has changed the historical geographic pattern of natural gas pricing, the competitive effects of natural gas-fired power generation are frequently more severe. Because only a subset of coal-fired generation resources is subject to head-to-head competition from natural gas-fired and other generation resources, a focus on average prices and costs may overlook significant competitive impacts for certain markets and coal-fired generators.

The ultimate effect of these changes is reflected in the fall of the share of electricity produced from coal-fired generation and the increase in that produced from natural gas-fired generation. (See Figure 4 above.) Over the most recent twelve months for which there are data, coal-fired power production fell by 13% from the previous twelve-month period, while natural gas-fired power production increased by 17%.[37] In order for this rapid shift away from coal-fired generation to natural gas-fired generation to occur, more of the existing natural gas-fired

37 U.S. Energy Information Administration, *Electric Power Monthly*, September 2012 at Table 1.1.

generation capacity must be utilized (while less of the coal-fired generation capacity is used).

Natural gas-fired generation capacity from the first half of the 2000s, in retrospect, was overbuilt, as many of these new relatively efficient natural gas-fired generation resources ran less often than originally anticipated by their owners, due in part to weaker-than-expected demand growth and a run-up in natural gas prices through the middle of last decade.[38] By the late 2000s and the beginning of the shale gas revolution, however, there was ample relatively efficient natural gas-fired generation capacity in many locations to compete away sales of wholesale electric power from coal-fired generators. Figure 16 shows that the utilization rate of existing coal-fired generation capacity fell from 71% in 2007 to 61% in 2011, while the utilization rate for NGCC generation capacity grew from 42% in 2007 to 44% in 2011. For the first part of 2012, NGCC generation capacity was used more intensively than coal (51% versus 50%, respectively); power generated from natural gas to a substantial extent is replacing power previously generated by coal.

### *Changes in the Supply of Wholesale Electric Power*

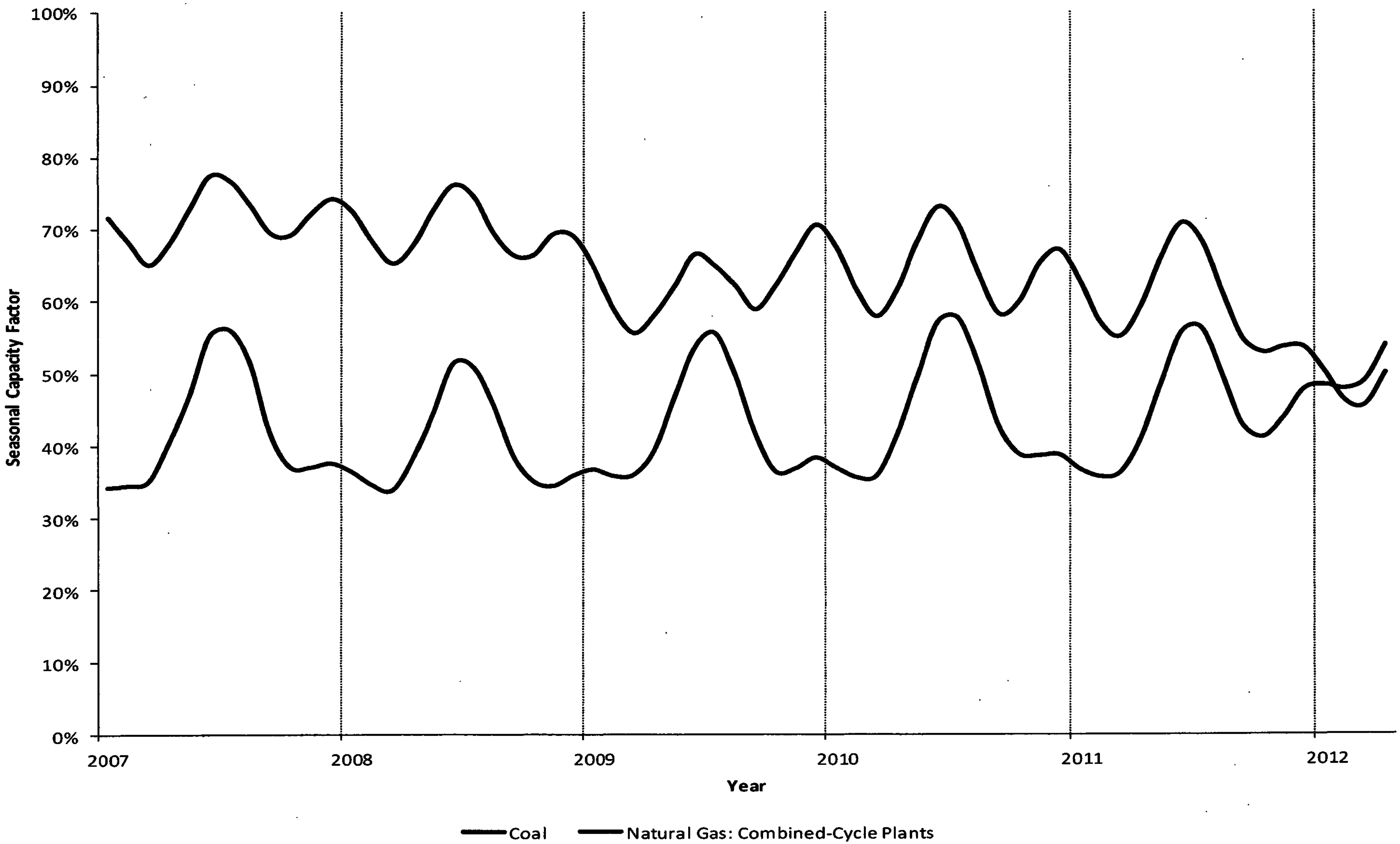
The significant displacement of coal-fired generation by natural gas-fired generation is a natural result of the forces discussed above: the increase in relative fuel efficiency (and flexibility) of natural gas-fired generation to coal-fired generation; the decrease in the delivered-to-power-plant price of natural gas

[38] A new NGCC plant typically takes between two and four years from initial planning to operation, so the additions reflect expectations from an earlier period.

Figure 16

**CAPACITY UTILIZATION: COAL-FIRED v. NGCC GENERATION**

2007-2012




Notes: Seasonal Capacity Factor (%) uses the appropriate Summer/Winter capacity depending on the month. The months of June-September are considered Summer months and the months of October-May are considered Winter months.
Source: Ventyx, Monthly Plant Production Cost Dataset.

relative to coal; and prospects of additional fixed investment to sustain existing coal generation subject to stricter environmental regulations.[39] The economics of supply and demand for wholesale electric power demonstrate how these factors serve to displace coal-fired generation with natural gas-fired generation.

Figure 17 shows a wholesale power supply curve for the PJM RTO/ISO market based on generation and fuel prices for September 2012.[40] While the curve displayed is specific to the PJM RTO/ISO, other wholesale power markets are subject to the same economic principles that apply to this curve. Figure 17, like any competitive supply curve, relates the quantity of supply of electric power (i.e., megawatt ("MW")) to its price. One can imagine that potential power generation is stacked from lowest to highest marginal cost. Lowest-marginal-cost sources are supplied first—down and to the left in Figure 17. As the quantity of available low marginal-cost power is used, the next lowest quantity is set down and made available. Quantities of higher-marginal-cost electric power will not become available until the price is sufficiently high to cover those higher marginal costs. The available electric power generation amounts are added to the supply curve in order of low to high marginal cost, until there is no more to be provided. Figure 17

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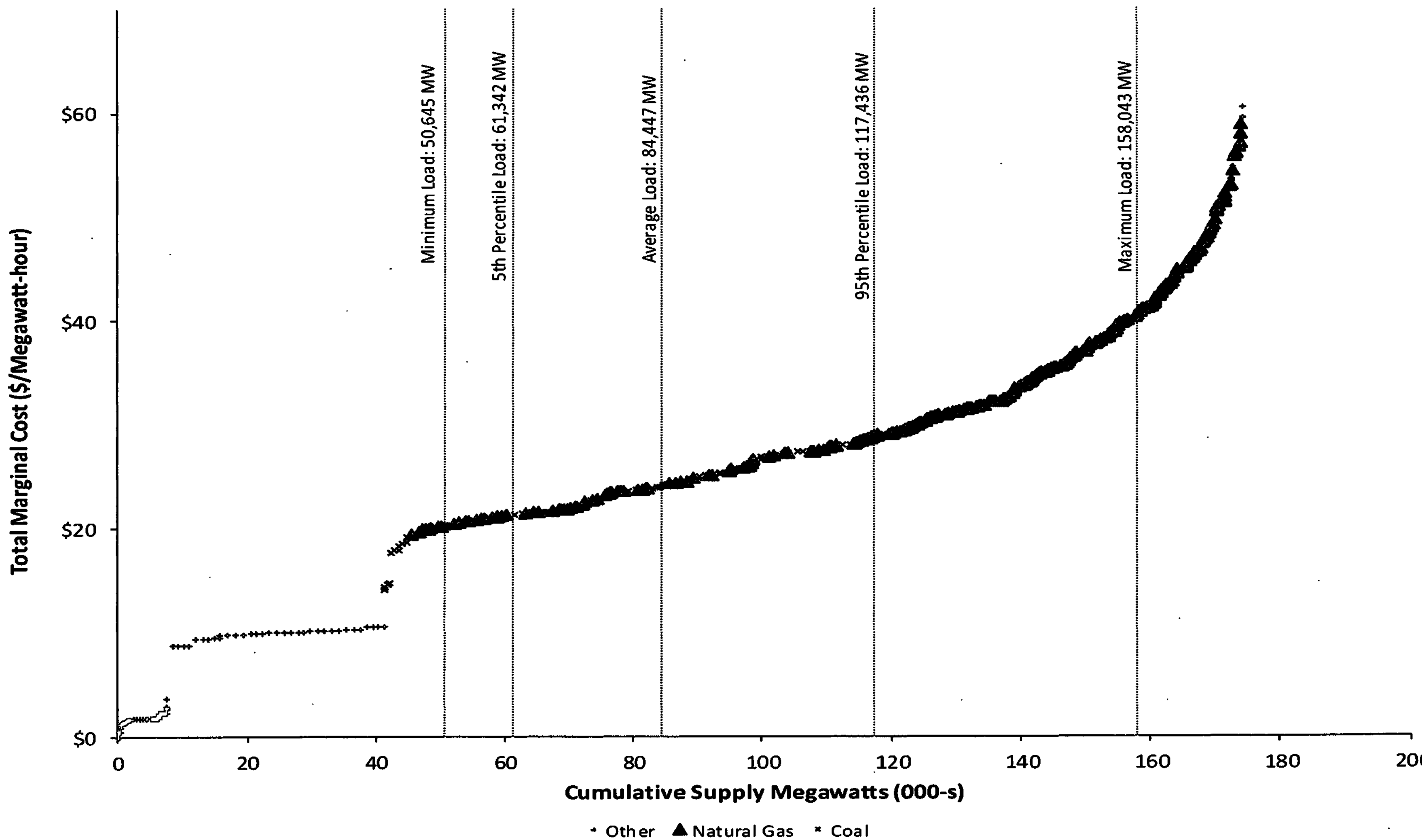
39 As intermittent generation sources, particularly wind power, become increasingly important, the ability to change output levels quickly and efficiently—the ability to "follow load"—has increasing economic value.

40 The PJM market covers all or parts of thirteen states and the District of Columbia, and stretches from the Mid-Atlantic region west to Illinois, with a combined population of 58 million people. The wholesale power supply curve depicted in Figure 17 is based on publicly reported data on marginal costs for individual generation resources and does not reflect actual supply offers for generation resources in the PJM market (though such offers generally are consistent with generation resources' marginal costs).

Figure 17

**ELECTRIC POWER SUPPLY CURVE: PJM BY FUEL TYPE**




Note: Removed high cost peaking supply for comparability. PJM supply curve is from September 3, 2012. Total marginal cost of generators modeled by Ventyx as the sum of: fuel cost, variable operations and maintenance cost, total NOx cost, total $SO_2$ cost, total $CO_2$ cost and total mercury cost. Fuel cost sourced from FERC Form 1, EIA-412, RUS-12, EIA-906/923, EIA-423, and Ventyx primary research.

Source: Ventyx

also indicates various levels of demand, in terms of the frequency in which this level of demand occurs. As previously seen, the demand for electricity varies substantially throughout the day and over the seasons. Supply and demand will be in balance when the market-clearing price is just sufficient to call in enough electric power generation supply to satisfy demand.

The supply curve in Figure 17 has a fairly typical pattern. There is a baseload supply of very low-marginal-cost power (in this case primarily nuclear and some low-cost coal generation) which would, if able, operate all the time because it provides power that is required even at the lowest level of demand. Past that minimum demand point there are numerous generation resources, a mix primarily of coal-fired and natural gas-fired generation that can supply the bulk of the non-baseload power. In Figure 17, the range between the fifth percentile of hourly load levels (i.e., the level of demand that is exceeded 95% of all hours) and ninety-fifth percentile of hourly load levels (i.e., the level of demand that is exceeded in only 5% of all hours) identifies those plants that would run frequently but not always. Plants located above the ninety-fifth percentile of hourly load levels on the supply curve would supply power rarely or only under extreme contingencies at higher prices.[41] The use of generation resources to meet load based on marginal costs (or offered prices) is known as *merit-order* dispatch.

41 These other high-cost plants can provide other services necessarily to maintain system reliability and a well-functioning power system such as various degrees of reserves for contingencies (such as an existing generator "tripping out" out of service).

Generation resources are not available 100% of the time to provide electric power as they are subject to both planned maintenance or upgrades and unplanned forced outages (e.g., due to the need to repair a boiler leak at a coal-fired generation facility). As such, at any hour the actual supply will depend on the generation available at that time. If some low-cost generation were unavailable, one can picture the quantity of supply available from that plant as being plucked out from the supply curve, and the higher-marginal-cost portion of the supply curve shifting slightly to the left to fill in the gap resulting from the unavailable generation.

The same principle applies when the marginal cost of generation changes for different generation sources. If a generator's marginal costs increase, it moves further up the supply stack (it shifts up in Figure 17 and thus also shifts to the right), and generators that had been higher marginal cost are now relatively lower marginal cost and move ahead in preferred stack of generation. In this way, changes in marginal costs among generators change the order of these generation resources along the supply curve.

As shown in Figure 17, the supply curve cuts through the fifth percentile of hourly load levels and the ninety-fifth percentile in a relatively narrow range of prices from $22.23 per megawatt-hour to $28.83 per megawatt-hour. Abstracting from reliability, security, and flexibility issues, whether a generator were to run no more than 5% of the time or up to 95% of the time depends on whether its marginal cost is at the low or high end of that narrow range. As such, small changes in the marginal cost of electric power production can dramatically impact how often a generator runs and the revenues earned by that generator.

As can be seen for PJM in Figure 17, there is substantial intermixing between coal-fired and gas-fired generation in terms of the stack of generation that makes up the supply curve. The particular order reflects differences in fuel efficiency, delivered fuel supply costs, and other operating and maintenance costs among the generation resources. Small changes in any of those factors (including the cost of delivered fuel) will change the order in which it is economic to run particular resources, and thus determine whether particular gas-fired or coal-fired generation resources will be operating.

These economics of supply and demand explain how natural gas-fired generation displaces coal-fired generation, and how this can provide competitive constraints on input suppliers (like railroads) for delivered fuel for coal-fired generation. Small changes in marginal costs for a generation resource will shift the order in which these costs show up in the supply curve. Rather than satisfy the need for wholesale power with power generated from coal, the now lower-marginal-cost power from gas-fired generation is purchased first. The observed effect, as seen in Figure 16 above, is that the changes in the market have resulted in natural gas-fired generation running more often, and coal-fired generation running less often.

Another implication of this re-ordering of marginal costs and resulting generation on the supply curve is that the owner of a coal-fired generation resource that runs less often, and with a lower mark-up between the market-clearing price and its marginal cost, will be less willing to incur ongoing fixed costs (the costs of continued operation and maintenance necessary to keep the resource in service irrespective of whether it actually runs or not) and less willing to make new capital additions or replacements, such as those necessary to meet new emission standards. For both of these reasons, when and where natural gas-fired generation competes more successfully against coal-fired generation, higher-marginal-cost coal-fired generation resources (relative to competing natural gas-fired generation resources) will be more likely to shut down and retire, rather than incur future costs to remain in service. Obviously, if a coal-fired generation resource shuts down, competition from gas-fired generation will not discipline input prices to that plant, as there are no sales of coal or railroad services left to discipline.

***Examples of Displacement of Coal-Fired Generation by Natural Gas-Fired Generation***

The significant displacement of coal-fired generation by natural gas-fired generation described above has been widely discussed and reported. Top executives of major power generators have confirmed that the competitive fundamentals of the wholesale power market have changed, and there are numerous publicly reported examples of different forms of the displacement of coal-fired generation by natural gas-fired generation for specific coal-fired generation facilities.[42]

*Reported Examples of Displacement of Coal-Fired Generation by Natural Gas-Fired Generation in RTO/ISO Markets*

First Energy, Ohio, Pennsylvania, and Maryland.

> In its heyday, the giant W.H. Sammis power station [2,233 megawatt capacity] was a workhorse, cranking out electricity around the clock. But FirstEnergy Corp. now plans to idle the coal-fired power plant on the Ohio River and run it only when there is exceptional need for electricity.[43]
>
> FirstEnergy Corp....will retire six aging coal-fired power plants with a capacity of nearly 2,700 megawatts in Ohio, Pennsylvania and Maryland by September 1....[44]

Luminant, Texas.

> Luminant, recently announced plans to put two big, coal-fired generating units [1,200 megawatt combined capacity] at its Monticello power plant in northeast Texas into semiretirement.
>
> Luminant...says the change this year is prompted by market forces.

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42 Nicholas Akins, CEO of American Electric Power, on 4/20/2012 Quarterly Conference Call with Investors, describes how low gas prices are competing on a marginal basis with coal-fired generation: "there was always an assumption that coal is going to be lower than natural gas. Well, that's not the case, so we need to be flexible on both sides." http://seekingalpha.com/article/514591-american-electric-power-s-ceo-discusses-q1-2012-results-earnings-call-transcript?part=single, accessed October 1, 2012; Lynn Good, CFO of Duke Energy on 2/16/2012 Quarterly Conference Call with Investors, explaining that the decision to run coal resources is based on conditions in the wholesale market: "we run [our coal resources] in an economic manner. If the coal is in the money we run them. If it's not in the money, we don't." http://www.duke-energy.com/pdfs/Q42011-DUKE-Transcript-2-16-2012.pdf, accessed October 1, 2012.

43 Smith, Rebecca, "Coal-fired Plants Mothballed by Gas Glut," *Wall Street Journal*, September 11, 2011. This is despite FirstEnergy having completed a $1.8 billion environmental retrofit of this plant in 2010.

44 Beattie, Jeff, "Greens Dispute FirstEnergy On Shutdown Of Coal Plants," *The Energy Daily*, January 30, 2012.

> That is because natural-gas plants set market prices in Texas, and their costs are so low that they can often sell power for less than what it costs to run a coal plant. One reason Luminant's costs are higher is because of coal-handling expenses and the higher number of employees it takes to run a coal plant compared with a gas-fired plant.
>
> "It's all about low wholesale prices," said Luminant spokesman Allan Koenig.[45]

American Electric Power, Ohio, Indiana, West Virginia and Virginia.

> Ohio-based American Electric Power Co. started down this path a couple years ago, changing the operating status of 10 generating plants in Ohio, Indiana, West Virginia and Virginia. Today, it keeps a skeleton crew at each location and brings in more workers when it wants to bring some of the coal units back to life, something that requires about four days' notice.
>
> AEP's annual coal burn has dropped from approximately 75 million tons before 2008 to a projected 55 million tons in 2012. The multistate utility's natural-gas use, over that same period, had doubled, to about 200 billion cubic feet. [46]
>
> AEP's executives reported that the company's natural gas consumption had increased 62% year over year, and that with the exception of one plant, its gas-fired combined cycles in the eastern part of its system were operating at an 85% capacity factor....AEP's CEO said that the company increased its overall natural-gas capacity by 24 percent last year, and it expects to increase that by another 14 percent this year....At the peak of 2007 and 2008, we were taking [and burning] about 80 million tons of coal a year.....Today, that's probably down to the order of 55 million tons of coal a year.[47]

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45 Ibid.

46 Ibid.

47 In part from National Review, "War Over Natural Gas About to Escalate," May 3, 2012, cited in Tierney, Susan F, "Why Coal Plants Retire: Power Market Fundamentals as of 2012," *Coal Power*, July 30, 2012

PPL, multiple locations.

> PPL Corp., of Allentown, Pa., is considering putting some of its coal units into formal part-time operating status, too, said George Lewis, a company spokesman. Several PPL units in the Midwest and Northeast were sidelined for extended periods this past spring because there weren't buyers for their power. The company expects power prices to remain low for the next couple of years, potentially idling units "for even longer periods," he said.[48]

AES, Indiana, Ohio, and New York.

> The coal-fired generating assets within both IPL [Indianapolis Power and Light] and DPL [Dayton Power & Light] have experienced reduced output associated with the decline in coal price relative competitiveness in their merit order dispatch. In 2011, Eastern Energy, our coal-fired plants in New York, filed for bankruptcy and is no longer in our portfolio of businesses.[49]

*Reported Examples of Displacement of Coal-Fired Generation by Natural Gas-Fired Generation in Bilateral Electricity Markets*

Southern Company, Alabama, Florida, Georgia, and Mississippi.

> Southern Co. executives recently reported on their Q1 2012 earnings call (Apr. 25, 2012) that in 2007, the company's electricity production was 16% natural gas and 70% coal. They now expect that the mix for 2012 will be 47% natural gas and only 35% coal. Its natural gas combined cycle plants have been operating at a 70% capacity factor, and the company estimates that its purchases of natural gas made up 2% of total gas consumption in the U.S.[50]

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48 Ibid.

49 AES Corp. 10-Q filing, August 6, 2012 at 46.

50 Tierney, Susan F., "Why Coal Plants Retire: Power Market Fundamentals as of 2012," *Coal Power*, July 30, 2012.

Santee Cooper, a publicly owned utility, South Carolina

> Santee Cooper is making heavy use of its only natural gas-fired station and purchasing large amounts of gas-fired power from others to mitigate the economic effect of being one of the nation's most coal-dependent utilities, Santee Cooper's President and CEO Lonnie Carter said in an interview.
>
> "On average, we're importing 600 to 800 MW a day" of purchased gas-fired power to the heart of Santee Cooper's wholesale and retail customer base in coastal or "downstate" South Carolina, Carter said.
>
> The gas-fired power Santee Cooper is buying under a mix of long-, medium- and short-term deals is "very economical right now,"...the utility expects to continue making such purchases as long as they remain economical.
>
> Carter noted that South Carolina has a "robust" transmission network...and there is sufficient transmission capacity available for the utility to continue or expand its purchases of gas-fired power.[51]

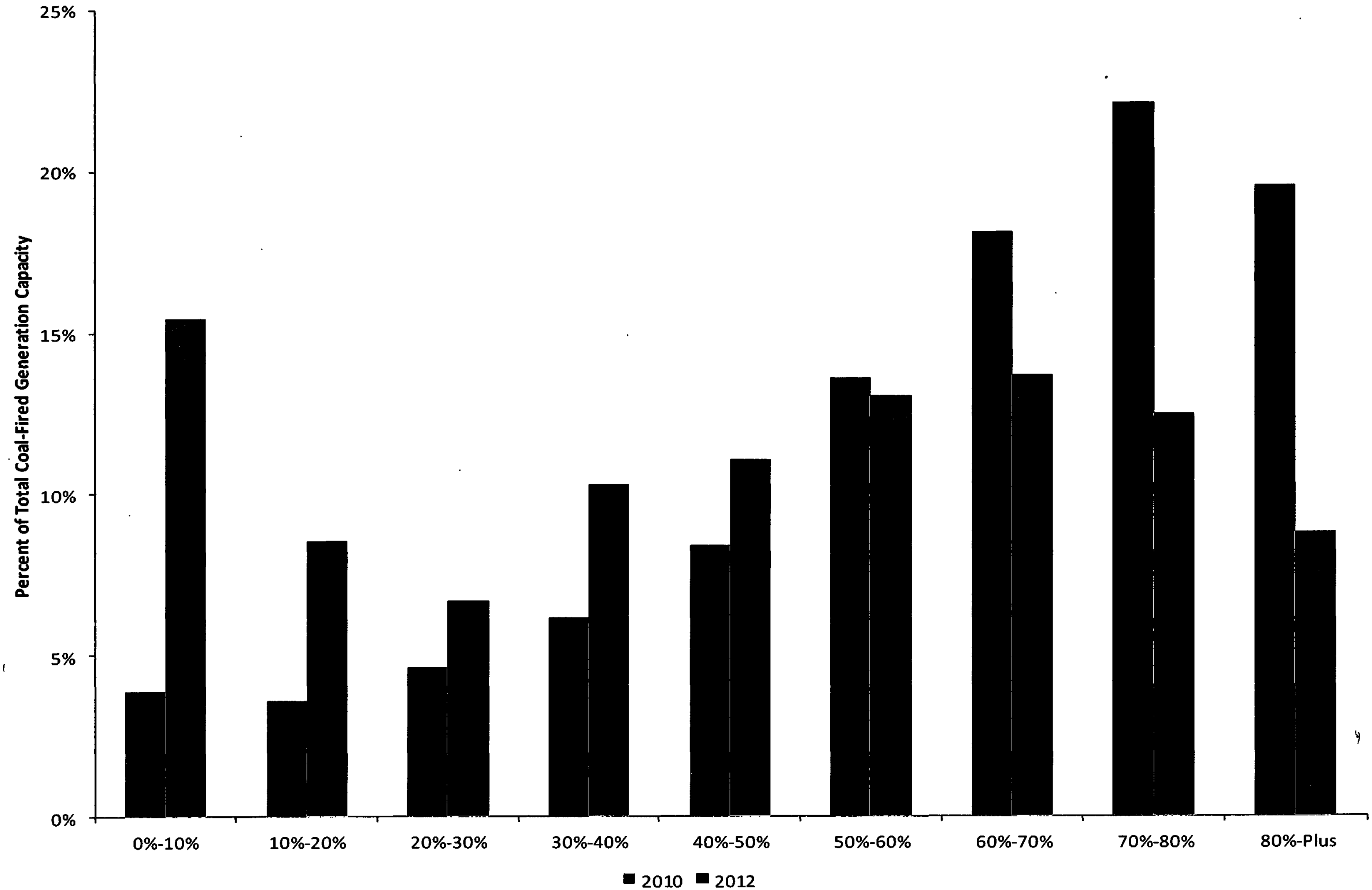
### *Displacements and Retirements of Coal-Fired Generation*

The data on capacity utilization by coal-fired generation bear out the impacts of the retirements of high-cost coal-fired generation resources and the reduction in the utilization of remaining coal-fired generation resources because their output has been displaced by natural gas-fired generation. Figure 18 shows how the distribution of coal-fired generation capacity utilization has shifted in just two years. Figure 18 shows that in 2010, 20% of the existing coal-fired generation capacity operated at a utilization rate of 80% or greater (44% at greater than 70% utilization)—generally consistent with baseload operations, while only 7% of coal-fired generation capacity operated at less than 20% of capacity. By the first part of 2012, Figure 18 shows a large shift in the pattern of coal-fired utilization. Only 25%

[51] "Gas reliance increases for Santee Cooper," Electric Power Daily, September 6, 2012.

Figure 18

## CAPACITY UTILIZATION OF COAL-FIRED GENERATION HAS DECLINED




Note: Year 2012 is a partial year. Data available for the first six months.
Source: Ventyx, Unit Generation and Emission Dataset.

of the capacity is used 70% of the time; 24% is utilized less than 20% of the time; and there has been a general shift downward in the capacity utilization for coal-fired generation that had been running at intermediate levels.

This pattern is consistent with the preceding analyses of the increased head-to-head competition between coal-fired and natural gas-fired generation. While there are some baseload coal-fired generation resources that have not had their output displaced by natural gas-fired generation, there are a number of coal-fired generation resources that have been mothballed or run at only very low levels. Put simply, much coal-fired generation capacity has been subject to some degree of competition with natural gas-fired generation and natural gas-fired generation has displaced a substantial portion of the electric power previously produced by coal-fired generation. EIA's projection of electric generation capacity additions by fuel type between 2011 and 2035, as illustrated in Figure 19, suggest that competition from natural gas-fired generation will continue into the future.[52]

### *Effects on Railroads of Competitive Displacement of Coal-Fired Generation by Natural Gas-Fired Generation*

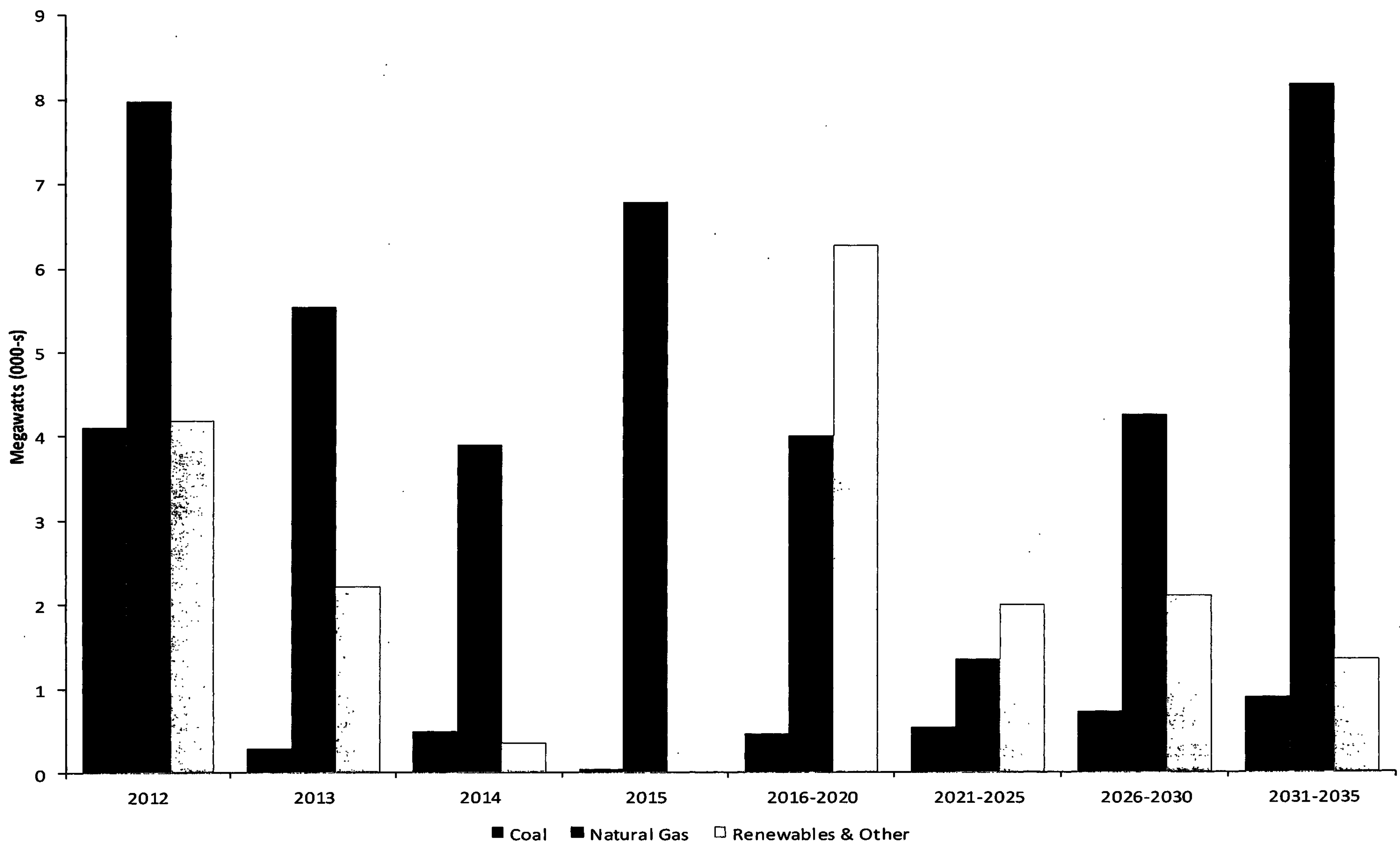
Railroads, as the primary transporter of coal, have been substantially affected by the competitive displacement of coal-fired generation by gas-fired

[52] In a similar vein, EIA and some electric power industry analysts project significant retirements of coal-fired generation capacity as a result of increased environmental regulation and continuing competition from natural-gas fired generation. See for example, Celebi, Metin, Frank C. Graves, Gunjan Bathla, and Lucas Bressan, "Potential Coal Plant Retirements Under Emerging Environmental Regulations," The Brattle Group, Inc., December 8, 2010; Celebi, Metin, Frank Graves, and Charles Russell, "Potential Coal Plant Retirements: 2012 Update," The Brattle Group, October 2012; U.S. Energy Information Administration, "27 gigawatts of coal-fired capacity to retire over next five years," July 27, 2012.

Figure 19

**PROJECTED ELECTRIC GENERATION CAPACITY ADDITIONS BY FUEL TYPE**

2011-2035




Note: Projections provided by U.S. Energy Information Administration. Projections across five-year period, after year 2015 projection, are annualized.
Source: U.S. Energy Information Administration, Electric Power Annual 2010, Release Date: November, 2011. U.S. Energy Information Administration, Annual Energy Outlook 2011.

generation. For the first 36 weeks of 2012, U.S. railroads' carloadings of coal were down by over 9% from the same period in the previous year, or over 45 million tons.[53] This effect is especially severe for the eastern railroads, as CSX and NS total carloadings were down by over 14% from the comparable previous period. This reduction in railroads' coal transportation has occurred despite record-high stockpiles of coal that electric power producers established in the first half of 2012.[54]

One public example can demonstrate the effect on rail transportation rates. In the spring of 2010, NRG Power Marketing filed a complaint with the STB that CSXT was market dominant and that the applicable tariff rates for transportation of coal to the Dunkirk and Huntley coal-fired power plants in New York were unreasonable.[55] NRG argued in a petition for injunctive relief that power produced by the coal plants competed on price and that rail transportation rate reductions were necessary in order for NRG to compete more effectively in the wholesale power market in New York.[56] (Shortly after NRG filed its rate case, CSXT and NRG reached a commercial agreement and the rate case was dismissed.)

In spring 2012 NRG filed for permission to mothball the Dunkirk plant, and then filed an informational response to the New York state-sponsored Energy

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53 Association of American Railroads, "Weekly Traffic of Major U.S. Railroads For the Week Ending September 8, 2012."

54 U.S. Energy Information Agency, *Short-term Energy Outlook*, September 11, 2012, at Figure 22, U.S. Electric Power Sector Coal Stocks.

55 STB Docket NOR 42122, NRG filing, May 18, 2010.

56 STB Docket NOR 42122, NRG filing May 25, 2010 at 3.

Highway Task Force for two projects: one would convert the Dunkirk plant to a combined cycle plant only using natural gas, and the second would permit the Huntley plant to run on either coal or natural gas. CSX has no incentive to raise rail rates on coal movements above competitive levels such that it loses the traffic due to competition from other power generation. The difficulties of coal-fired generators in upstate New York do not arise from an exercise of market power by railroads, but from competition from other generation sources. Competition with natural gas generation has recently caused other New York state coal-fired generation facilities to close. Two AES-owned plants closed in March 2011, and two others declared bankruptcy at the end of 2011.[57]

This displacement of coal-fired generation by natural gas-fired generation demonstrates that indirect competition for rail transportation of coal for electric power generation effectively constrains rates for such transportation to competitive levels for at least some coal-fired generation facilities.

While these examples demonstrate that competition from natural gas-fired generation can effectively constrain rail rates for coal transported to certain coal-fired generation resources, a number of factors have so far muted the effect of the displacement of coal-fired generation on railroads and rail pricing. First, both coal supply and rail transportation of coal tend to be provided under long-term contracts that often include minimum volume commitments (e.g., take-and-pay contracts for

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57 "AES New York Subsidiary Declares Bankruptcy on Coal Woes," *PowerNews*, January 4, 2012.

coal supply). To the extent the coal-fired power producer is subject to volume-based penalties or bonuses in existing coal supply and transportation contracts, these penalties or bonuses may for a time provide incentives to limit reductions in the purchasing and transportation of coal. Also, transportation rates negotiated under more favorable (to shippers) market conditions in unexpired contracts delay exposure to new market conditions. When such contracts do come up for renewal, however, coal-fired generation resources subject to extensive head-to-head competition from natural gas-fired generation will not pay more for delivered coal than the competitive downstream energy markets will bear, and coal supply and transportation rates, including rail rates, must reflect that change.[58]

While publicly available data on the cost of delivered coal used in electric generation is available to some extent, the cost of railroad transportation to power generators is not. Since rail transportation contracts for coal are private, public information on rail rates to individual plants depends on estimates and reports. The information available indicates that the competitive pricing pressure on the

58 See, for example, comments of Nicholas Akins, CEO of American Electric Power, 4/20/2012 Quarterly Conference Call with Investors: "...we're becoming more flexible in terms of our coal contracting to ensure that we do have the flexibility if natural gas prices continue to be low, which we expect they will, that we'd be able to respond from a contractual standpoint." http://seekingalpha.com/article/514591-american-electric-power-s-ceo-discusses-q1-2012-results-earnings-call-transcript?part=single accessed October 1, 2012.

cost of delivered coal has resulted in reductions in the anticipated prices of coal transportation, and in some cases the nominal rate.[59]

## V. SIMPLE ANALYSES BASED ON PUBLICLY AVAILABLE DATA CAN ACCURATELY IDENTIFY INDIRECT COMPETITION FOR RAIL TRANSPORTATION OF COAL USED IN POWER GENERATION

Indirect product and geographic competition—which does not involve direct transportation alternatives from origin to destination—is well understood to be a potentially strong competitive force. Demonstrating and evaluating these indirect competitive constraints on rail transportation rates, however, can be a more difficult process than analyzing direct competition. Frustration with this process as it existed in the late 1990s appears to have led the STB to eliminate the option of factoring in indirect competition when demonstrating the presence or absence of market dominance in rate cases in 1998. But since then changes in data and the structure of wholesale electric power markets have radically changed the process necessary to reasonably identify and evaluate the strength of these competitive alternatives relevant to transportation of coal used for power generation. These changes have created an ability to consider the effectiveness of indirect competition in a more efficient and straightforward way. By way of example, I offer two alternative forms of analysis of indirect competition on rail rates for transportation

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59 See, for example, Darren Epps, "Rail transportation rates down 25% from market levels since 2011," SNL Interactive (www.snl.com), September 4, 2012, which reports that "Dynegy Inc. said in August that it signed a contract for Powder River Basin delivery for about $20/ton--down from market expectations of about $28/ton in late 2011."

of coal exerted in the wholesale power markets that could be applied broadly using only readily available data and information.

### A. Data Availability

Over the last fifteen years the ability to collect and analyze large amounts of data cheaply and effectively has improved dramatically. At the same time, changes in the wholesale electric power markets have led to increased standardization and usefulness of the publicly collected and reported data, making previously difficult analysis of electric power competition commonplace. The process of collecting detailed plant- and company-level data has also been rationalized and simplified.[60]

#### *Geographic Markets*

Under Federal regulatory oversight and approval granted in 2007, the North American Electric Reliability Corporation has the authority to enforce grid reliability standards. As part of this function, the U.S. is divided into eight regional authorities and is then further divided into dozens of Balancing Authority Areas ("BAA"). The geographic BAAs usually contain load and generation and have well-defined interconnections with one or more other BAAs.

A Balancing Authority assumes responsibility for maintaining grid reliability and the electricity balance among its BAA's load, generation, and interchange with interconnected BAAs. Each Balancing Authority collects and makes available information on generation, load, a measure related to the hourly marginal cost of

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60 In conjunction with the FERC, the EIA in 2008 rationalized six different data collection efforts into two forms that have resulted in better and more consistent data on electric power generators.

power, and interconnects with adjacent BAAs. Excepting possible congestion constraints within the BAA, the BAA forms the basic geographic unit for market analysis in wholesale electric power markets.

### *Data Collection and Sources*

In addition to data collected about the BAAs from the Balancing Authorities, other data are collected that are valuable for analyzing indirect competition effects. Sources include:

**U.S. Energy Information Agency:** Collects detailed data on existing and planned generation.[61]

> **Electric Generator Report**. Detailed inventory of power plants, including ownership, location, grid interconnection, detailed engineering and pollution control components, current and future status (e.g., planned retirements), fuel type(s), pollution controls, etc. This provides a useful database of plant, generator-, and boiler-specific information that can be cross-referenced to other generation-related data.
>
> **Power Plant Operations Report.** Monthly level of electric power generation, fossil fuel consumed, delivered fossil fuel cost, information on sourcing and transportation of the fuel, and operational data.

**Environmental Protection Agency:** EPA has continuous emissions monitoring systems ("CEMS") at fossil fuel plants above a modest size.

> **CEMS Database:** The CEMS database contains information that permits the determination of hourly operation and gross generation from most fossil fuel plants. This permits detailed analysis of the operating decisions for both coal-fired and gas-fired plants.

**RTO/ISOs**: While it varies among ISOs, based on the ISOs' specific market structures, very detailed information is often available on daily (or hourly) market

61 Small generators (less than one megawatt of capacity) can report annually.

prices for power, bids, and generation and dispatch. Independent market monitors for each ISO also file reports on a regular basis evaluating market operations and issues.

**Non-governmental sources:** Due to active trading in both natural gas and wholesale electric power, detailed privately collected pricing information at various trade points throughout the U.S. are available through a variety of different sources.

Given the vast quantity of publicly available information now available, third-party, private value-added data aggregators and service providers are in the business of organizing and making these data available to subscribers in an easy-to-use fashion. Market participants in and regulators of the electric power industry regularly rely on these data sources and frequently utilize data aggregators and service providers to develop analyses of the competitive dynamics of the wholesale power markets and make marketing and regulatory decisions.

### *Market-Based Ratemaking*

Under Federal regulation, power generators can file for and may be granted approval to sell wholesale electric power at negotiated or market-based prices (i.e., not rates based on their administratively determined cost of service). Given the volume and overlapping nature of these filings—multiple generators seek approval in the same BAAs—a highly structured set of analyses and data is used to determine a presumption for (or against) a finding of no market power and authority for market-based rates.[62] The bulk of the filings pull from the same set of public data involving generation and load (supplemented by information provided

62 FERC Orders 697 (June 21, 2007), 697-A (April 21, 2008), 697-B (December 19, 2008), 697-C (June 18, 2009), and 697-D (March 18, 2010).

by the applicant that is generally relevant only to the applicant's filing). The specific forms used in the filings have been provided and calculations have been specified by the regulator for the market-power screens. Filings include detailed workpapers, most of which are public. The data and analysis for the most difficult portion of the calculation, the capacity limits on imports from neighboring BAAs, are now required to be made available by the BAAs themselves, so that there will be better accuracy and consistency. In addition to notification of changes, Federal regulators now require a resubmission by all approved generators every three years (staggered by region of the country).

The remarkable quantity and quality of publicly available data related to wholesale electric power markets permit reliable and detailed analyses regarding competitive forces that are relevant to rail transportation of coal for coal-fired generation. Given the procedures for obtaining and maintaining the ability to sell wholesale power at market-based prices, reliable data and well-defined methods for determining the scale and scope of competition in wholesale power markets are now readily available. Recent application of these data and methods provides a valuable resource and foundation for analyzing indirect competition for the rail transportation of coal for electric power generation.

### B. Examples of Potential Analyses

The ready availability of rich and detailed data on various aspects of electric power generation and wholesale electric power markets provides a number of alternative methods for evaluating the competitive alternatives that exert indirect competition on rail rates for transportation of coal for electric power generation. Given the well-defined delineation of product and geographic markets in the wholesale power markets, standard data reporting, well-established methods and forms of analyses, and the required updates and triennial reviews for analyzing competition in wholesale power markets, the information and data already in the public record provide the means to look at these competitive alternatives expeditiously and efficiently.

I provide two examples of different methods or approaches for applying the available information on competition in the wholesale power markets to evaluate the indirect competition exerted by the wholesale electric power markets on rail transportation of coal for electric power generation. In these examples, I apply the methods to two rail-served, coal-fired power plants based on actual data. To focus on the concepts rather than on specific issues, I identify these power plants as Plant ABC and Plant XYZ. The examples do not represent specific proposals for the implementation of definitive screens for indirect competition exerted by the wholesale electric power markets. Rather they are intended to illustrate alternative methods of analysis that can be readily performed utilizing already available public information and standard methods for looking at these issues.

#### *Example 1: Changes in Coal-Fired and Natural Gas-Fired Generation Output*

One approach that utilizes readily available public data involves examining how a coal-fired power plant served by a railroad responds to changes in the relative prices of coal and natural gas. As discussed above, some low-cost, coal-fired power plants may continue to run as baseload plants even in the presence of low natural gas prices, while, as has clearly been the case in many wholesale power markets in recent years, other coal-fired plants will see their generation output displaced by natural gas-fired generation output. Thus, an analysis of a change in generation output by a coal-fired power plant as natural gas prices and natural gas-fired generation output change may provide evidence that demonstrates the competitive constraint on rail transportation rates exerted by competition between a particular coal-fired power plant and other generation resources (here, very likely to be natural gas-fired generation) in the wholesale power markets.

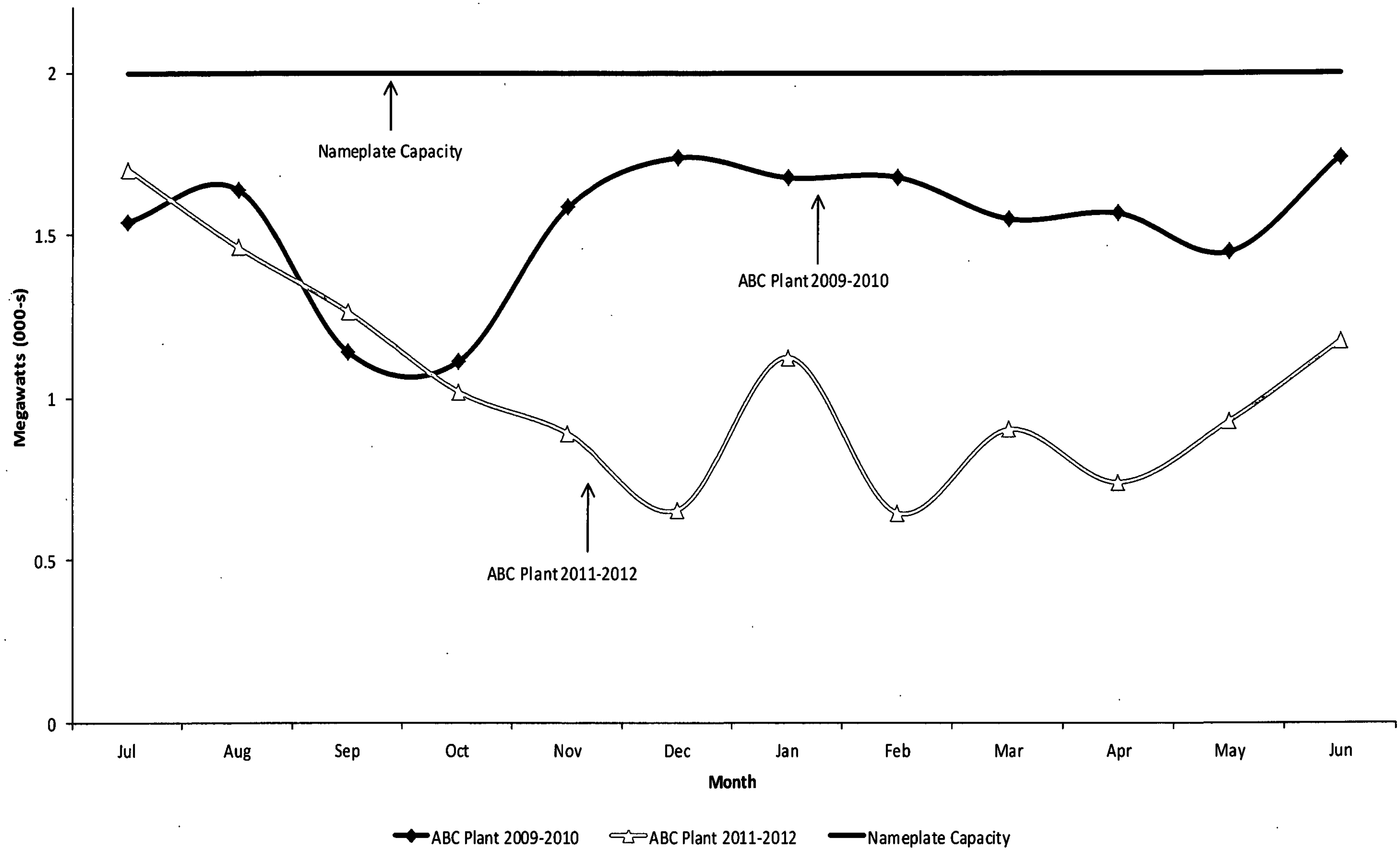
The idealized baseload plant (with no outages) runs at its optimal output level in all hours of the year. Recognizing that there are both planned and forced outages, this doesn't happen in practice. When faced with effective competition from natural gas-fired or other generation, traditional coal-fired power plants, which often have difficulty quickly and efficiently changing output levels, can adopt different strategies for managing production. During periods of lower demand, the plant can run at its minimum load during the off-peak portion of the day when electricity prices may be lower (e.g., 10 pm to 6 am) and then ramp production up during the higher-demand, higher-priced portion of the day. Alternatively, or in addition, the coal-fired power plant may not run during some portion of the spring and/or fall seasons when demand drops and wholesale electricity prices tend to be lower. In either case, if the generation output pattern and levels of a coal-fired power plant respond substantially to competition from gas-fired generation, this is evidence of indirect competition on rail rates for coal delivered to that plant.

Relative changes in generation output in recent years have provided a clear opportunity to see the effect of this natural gas-on-coal competition. Using publicly available data, Figure 20 shows the monthly pattern of electric power production for Plant ABC in the a recent twelve-month period relative to nameplate capacity and to the previous base twelve-month period. Due to the lower relative price of natural gas to coal, the more recent twelve months has been one of strong competition from natural gas-fired generation to coal-fired generation at least in some regions and for some plants. As such it provides a good natural experiment to examine whether natural gas-fired generation has displaced generation output from Plant ABC. If a significant reduction has occurred, then it is a good indicator that a significant increase in the relative delivered cost of coal for Plant ABC would also result in reduced generation output from Plant ABC. The reduction in generation output and the corresponding reduction in demand for coal and its transportation provide an effective competitive constraint on the price of rail transportation.

Figure 20 demonstrates a significant decline in the generation output of Plant ABC. The generation output fell by over 30% when comparing the two twelve-month periods. This decline is concentrated in periods—the first few months

Figure 20

## AVERAGE HOURLY PRODUCTION: ABC PLANT




Source: Ventyx, Unit Generation and Emissions Dataset.

of 2012—when natural gas prices were lowest and competition from natural gas-fired generation most intense.[63]

While the approach displayed in Figure 20 is simple, there are other ways of looking at the pattern of generation output from a coal-fired power plant in response to potential competition from natural gas-fired generation, such as monthly generation output, hours run, generation output at different hours of the day, and the like. The crucial part of the approach is that it utilizes the evidence on competition with respect to a particular plant, such as Plant ABC, made available by changes in the competitive circumstances of natural gas-fired generation. An analysis that shows that Plant ABC adjusts its coal consumption in response to relative fuel and electric power prices demonstrates that such competition provides an effective constraint on rail transportation pricing.

***Example 2: Wholesale Power Supply and Capacity Factor Curves***

As has been seen above in Figure 17, it is possible to create a wholesale power supply curve for a given geographic market or region based on information about fuel prices and plant characteristics. The supply curve represents the marginal cost of production and may not capture other aspects of a generator's operations that may affect its dispatch into the grid. What the supply curve does show, however, is where a particular generation resource's marginal costs fall

63 An analysis of average utilization of NGCCs in the BAA in which Plant ABC is located would show relatively high levels during the period when Plant ABC is lower.

among potential competitors, and for a coal-fired power generator, whether there appears to be substantial natural gas-fired generation in the same range along the supply curve. If a particular coal-fired generator is along the "flat" portion of the supply curve over which load fluctuates and for which small changes in short-run marginal costs can result in large shifts along the supply curve, this implies that the price elasticity of supply is high and the coal-fired generator risks a reduction in generation output and lost sales in response to an increase in its delivered cost of coal.

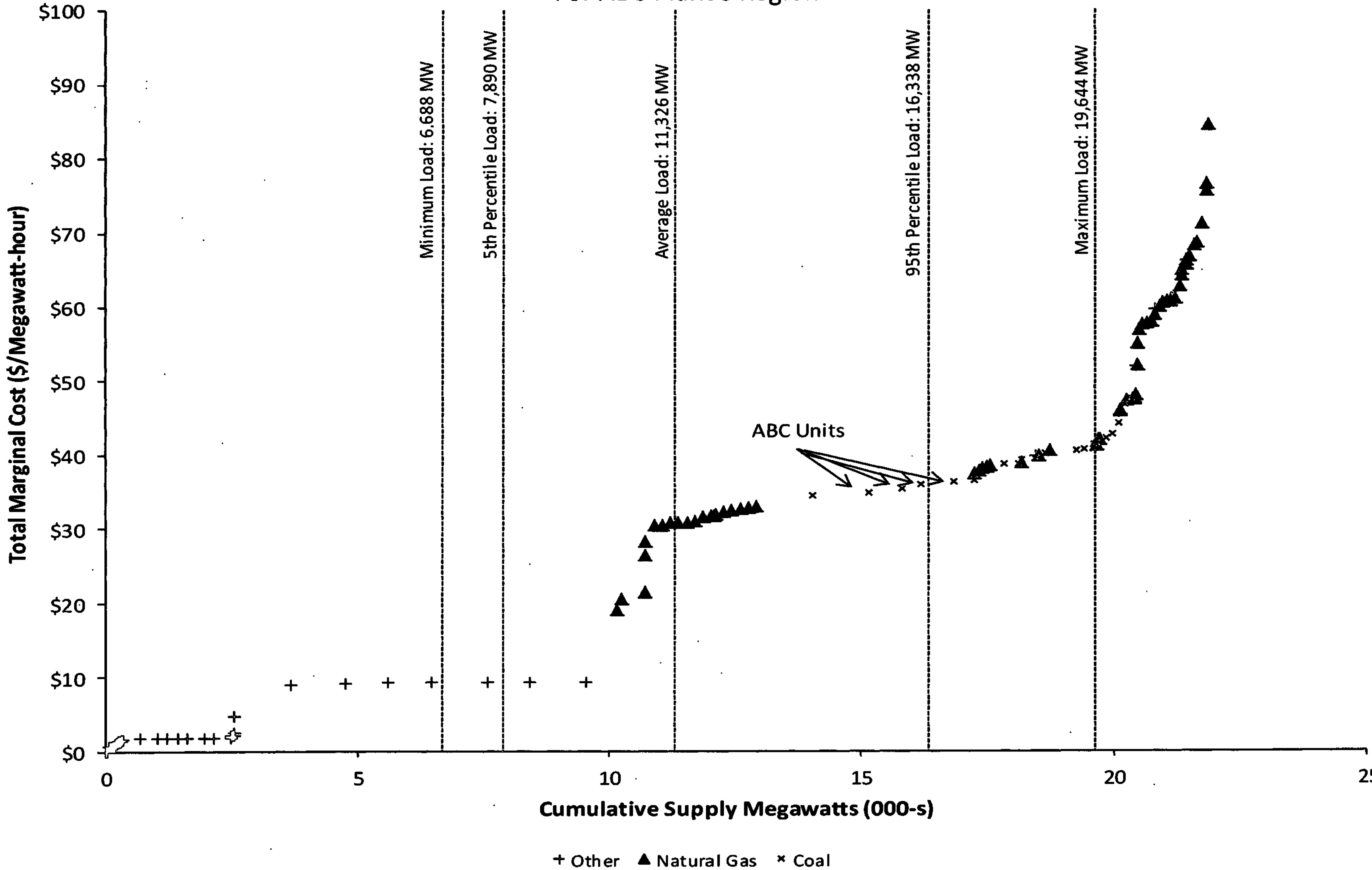
Figure 21 shows the supply curve for the BAA in which power Plant ABC is located, and identifies the four separate coal-fired generation units that constitute Plant ABC on that curve. Given fuel prices over the past twelve months, at current natural gas prices, a modest change in the delivered cost of coal for Plant ABC would substantially shift its location on the supply curve, and could easily result in substantial lost sales to natural gas-fired or alternative coal-fired generation. Output sensitivity to input prices can provide an effective constraint on important input providers such as railroads.

Another similar way of looking at this same competitive dynamic is to look at the relative generation capacity utilization rates, or capacity factors, for generation resources in the same geographic market. The capacity factor of a generation resource reflects its actual total generation output during a period divided by its

Figure 21

## ELECTRIC POWER SUPPLY CURVE BY FUEL TYPE

For ABC Plant's Region




Note: Removed high cost peaking supply for comparability. Supply curve is from September 3, 2012. Total marginal cost of generators modeled by Ventyx as the sum of: fuel cost, variable operations and maintenance cost, total NOx cost, total $SO_2$ cost, total $CO_2$ cost and total mercury cost. Fuel cost sourced from FERC Form 1, EIA-412, RUS-12, EIA-906/923, EIA-423, and Ventyx primary research.

Source: Ventyx

potential generation output during that period if it had operated all of the time at its full rated capacity.[64]

A baseload plant, subject to no effective competition, has the economic incentive to run at full capacity whenever it can, and thus, will have a relatively high capacity factor. Plants like Plant ABC, however, are subject to effective competition in some hours or days, and are economically compelled to reduce generation output at some of those times. During those times, Plant ABC would have difficulty passing on the costs of a higher delivered cost of coal without a loss in output and revenue, and thus a higher delivered cost of coal would result in reduced demand for coal and the transportation of coal.

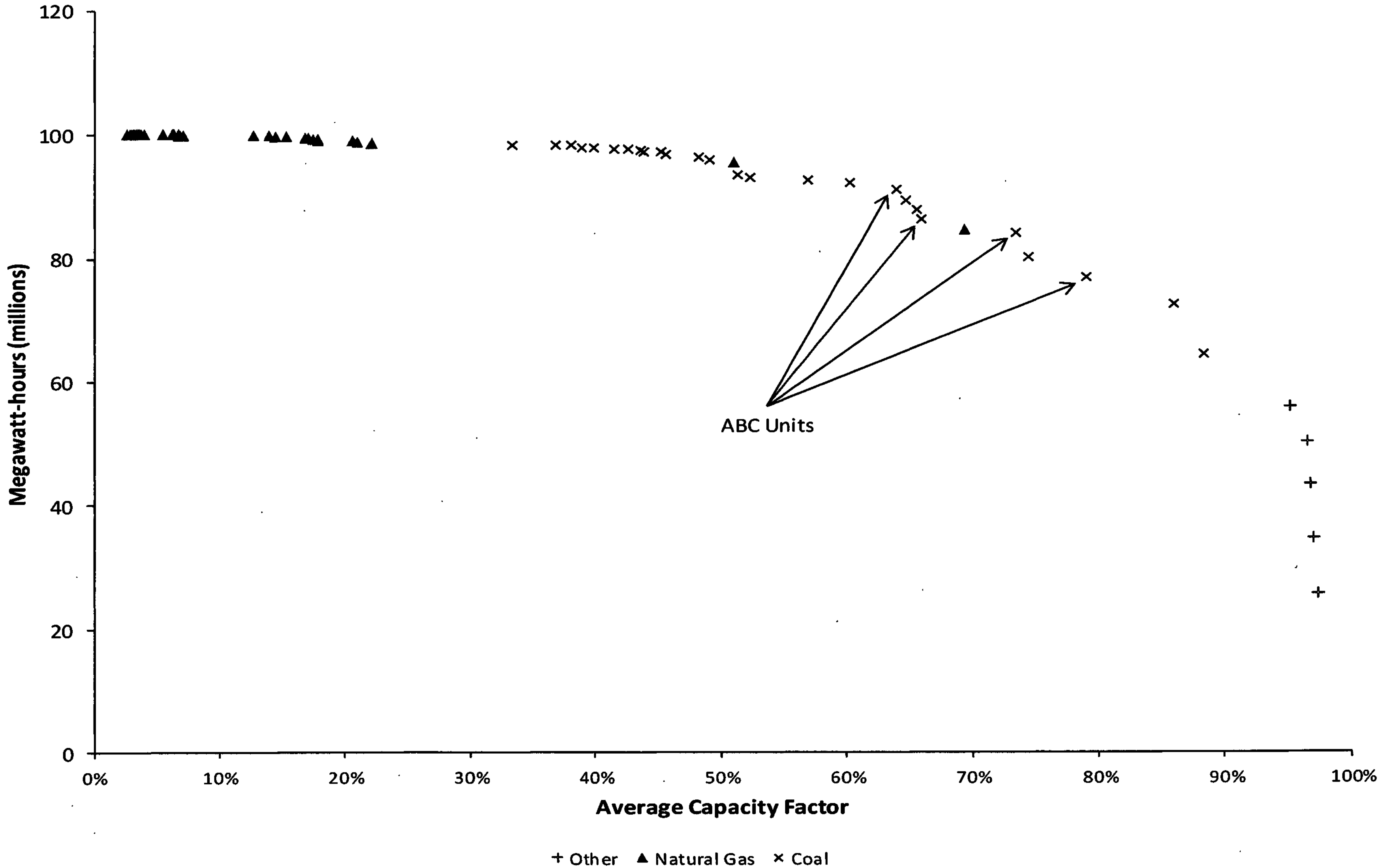
Based on actual data, Figure 22A provides a capacity factor curve for July 2010-June 2011 that shows the cumulative generation output for Plant ABC's BAA, ordered by the amount of generation output produced by different generation resources and the portion of the generation capacity of these resources that was utilized. In Figure 22A, the baseload generation resources with relatively high capacity factors are at the far bottom right of Figure 22A. As additional generation resources are added, ordered by their capacity factors, the amount of generation output for the period is accumulated, until the resources with the lowest capacity factors (typically peaking resources) are included and all generation output is accounted for. The generation resources at the bottom right in Figure 22 have the

[64] As in true in many industries, capacity factors can occasionally exceed 100% due to variances in anticipated maintenance and outages, and discrepancies between estimated outputs.

Figure 22A

**CUMULATIVE CONTRIBUTION TO TOTAL PRODUCTION IN ABC PLANT'S REGION BY CAPACITY FACTOR**

July 2010 – June 2011

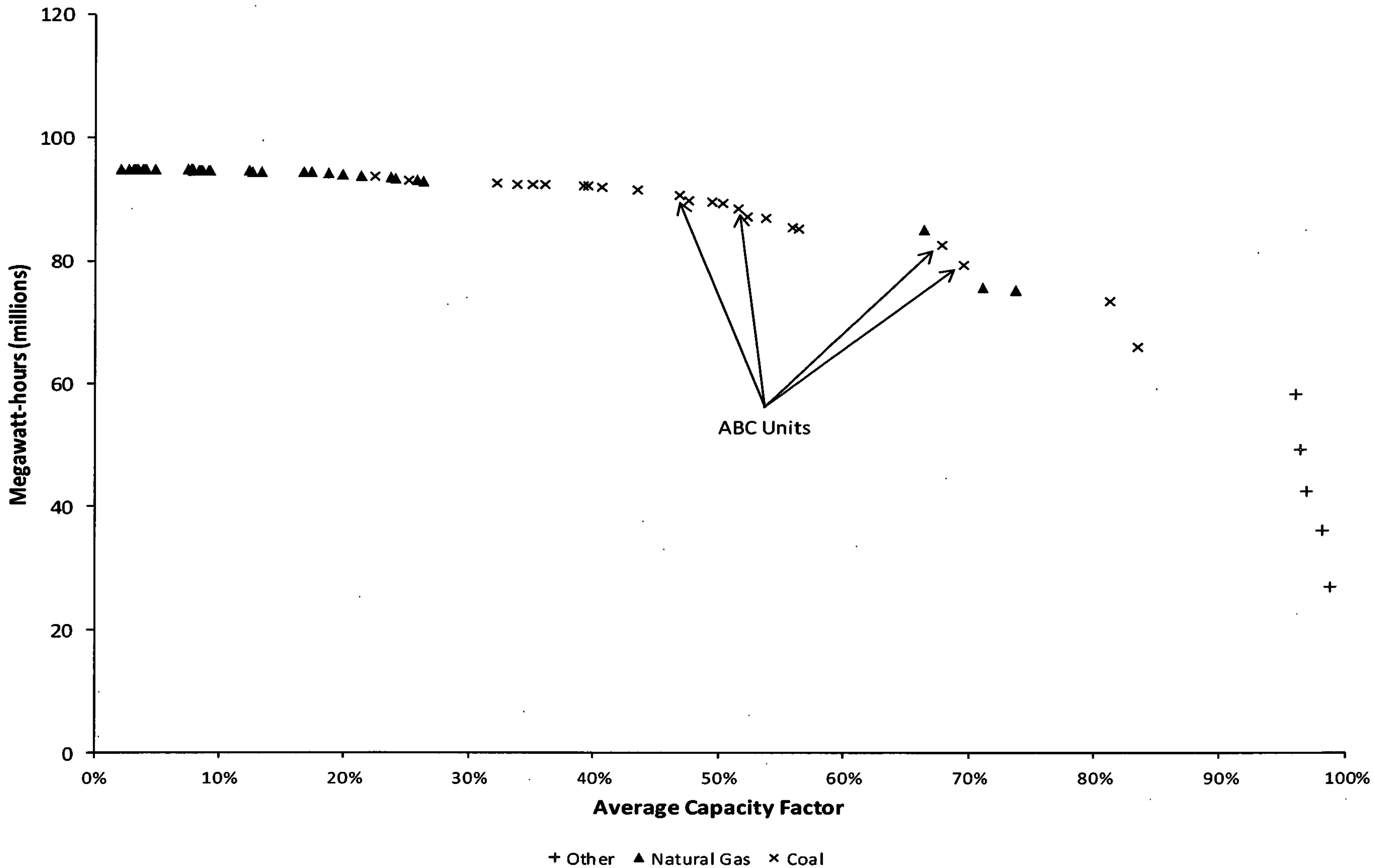



Source: Ventyx, Unit Generation and Emissions – Annual Dataset.

Figure 22B

**CUMULATIVE CONTRIBUTION TO TOTAL PRODUCTION IN ABC PLANT'S REGION BY CAPACITY FACTOR**

July 2011 – June 2012




Source: Ventyx, Unit Generation and Emissions – Annual Dataset.

highest capacity factors, while the resources at the upper left have the lowest capacity factors.

In general, if a generation resource has relatively high marginal costs (out at the upper right end of the supply curve) it will tend to have a lower capacity factor and will be near the vertical axis on Figure 22A. Figure 22A shows the location of Plant ABC on the capacity factor curve. To the extent that Plant ABC is located in the middle of the curve it would suggest that the plant may face competition much or all of the time, as it is choosing to produce well below its full capacity, presumably because it cannot produce generation output profitably all or even much of the time. To the extent that Plant ABC occupies a position on the flat part of the supply curve in Figure 21, it will be in the middle portion of Figure 22A.

As Plant ABC's competitive circumstance changes, due to increased competition from other generation resources, one would expect its location on both the supply curve and the capacity factor curve to shift. An examination of how responsive both would be in response to a hypothetical change in delivered fuel costs, or an examination of how these positions have changed over time in response to changing market circumstances, can provide ready information on the ability of competition in the wholesale electric power market to preclude an exercise of market power by an input supplier, such as that for rail transportation of coal.

Figure 22B shows the factor capacity curve for the same BAA for July 2011-June 2012. Compared to Figure 22A, Plant ABC's units have shifted up and to the left. The shift in the capacity factor is clearly observable and economically significant. The shift in utilization of Plant ABC's coal-fired units is consistent with the economics of wholesale power supply (see Figure 21) and with changes in relative delivered prices of coal and natural gas to power generation resources.

### *Counter-Example: Power Plant XYZ*

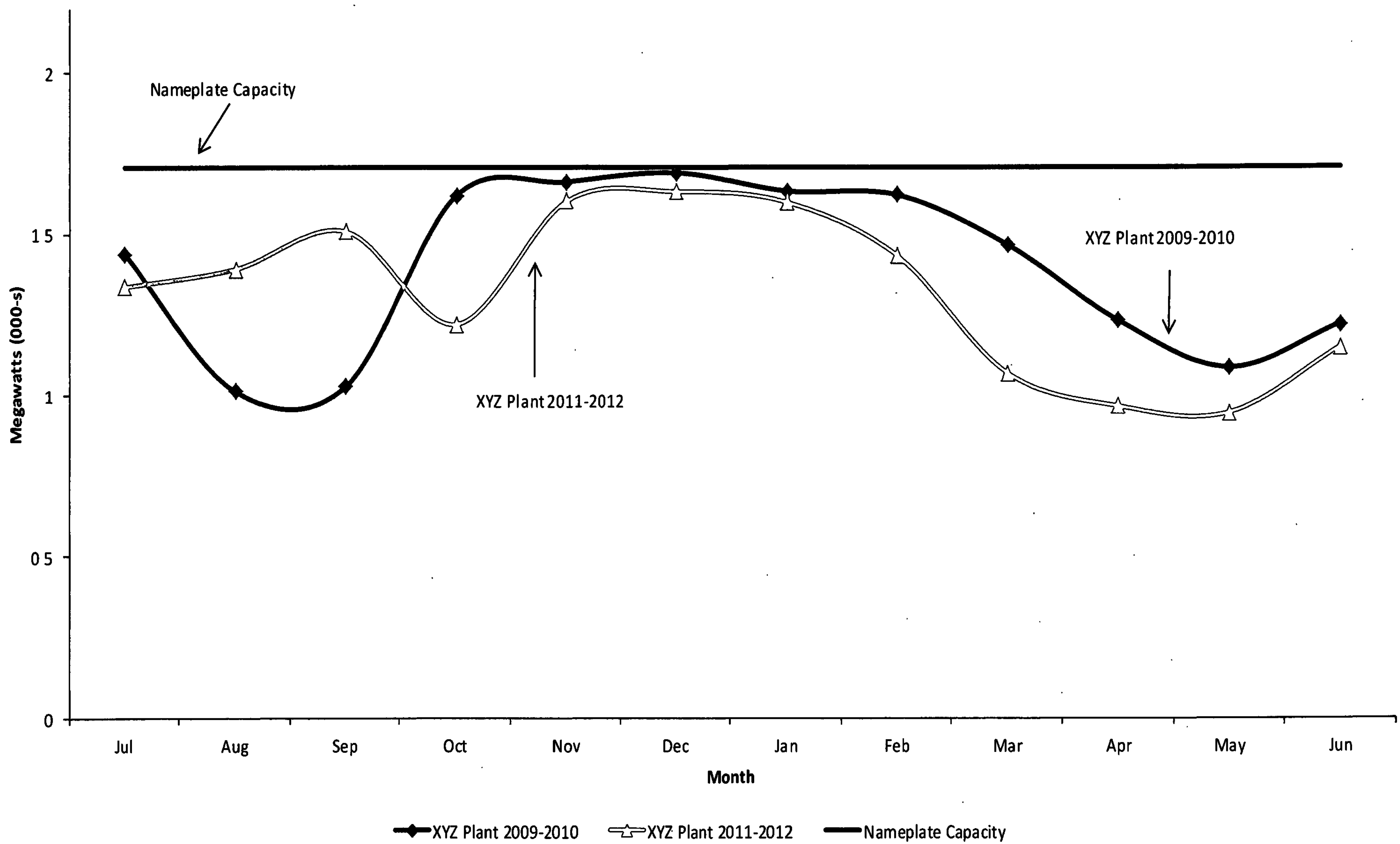
Figures 23 through 25B present similar calculations and analyses I have performed on another coal-fired power plant—Plant XYZ. Unlike the examples above for Plant ABC, the analysis and figures for Plant XYZ indicate that it continues to act like a baseload resource; there is thus no basis for finding that competition in the wholesale electric power markets between this coal-fired power plant and other generation resources, including natural gas-fired generation resources, would in and of itself effectively constrain the potential ability of a railroad to exercise market dominance over the rail transportation of coal to this plant. The contrasting examples demonstrate that the data and techniques used can distinguish among circumstances in which indirect competition on rail rates is exerted by competition in the wholesale power markets, and when it is not.

### *Interpretation of Examples*

The examples above demonstrate how changes in the wholesale electric power and natural gas markets and the availability of consistent, publicly available data regarding these markets have made it possible, in a fast and streamlined way, to analyze competitive factors in the wholesale power markets relevant to the issue of indirect competition exerted in the wholesale power markets and its effects on the

Figure 23

## AVERAGE HOURLY PRODUCTION: XYZ PLANT

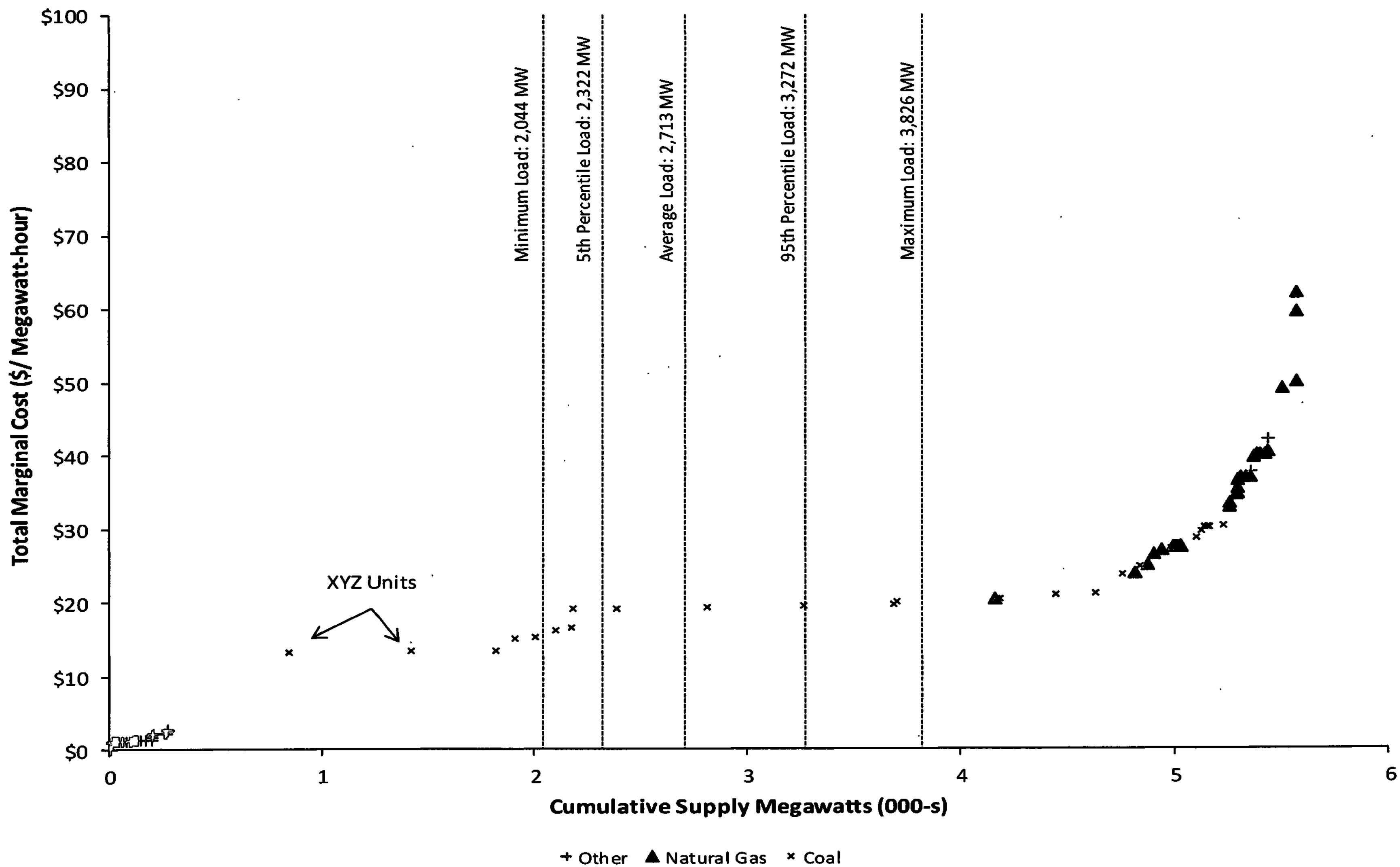



Source: Ventyx, Unit Generation and Emissions Dataset

Figure 24

## ELECTRIC POWER SUPPLY CURVE BY FUEL TYPE

For XYZ Plant's Region



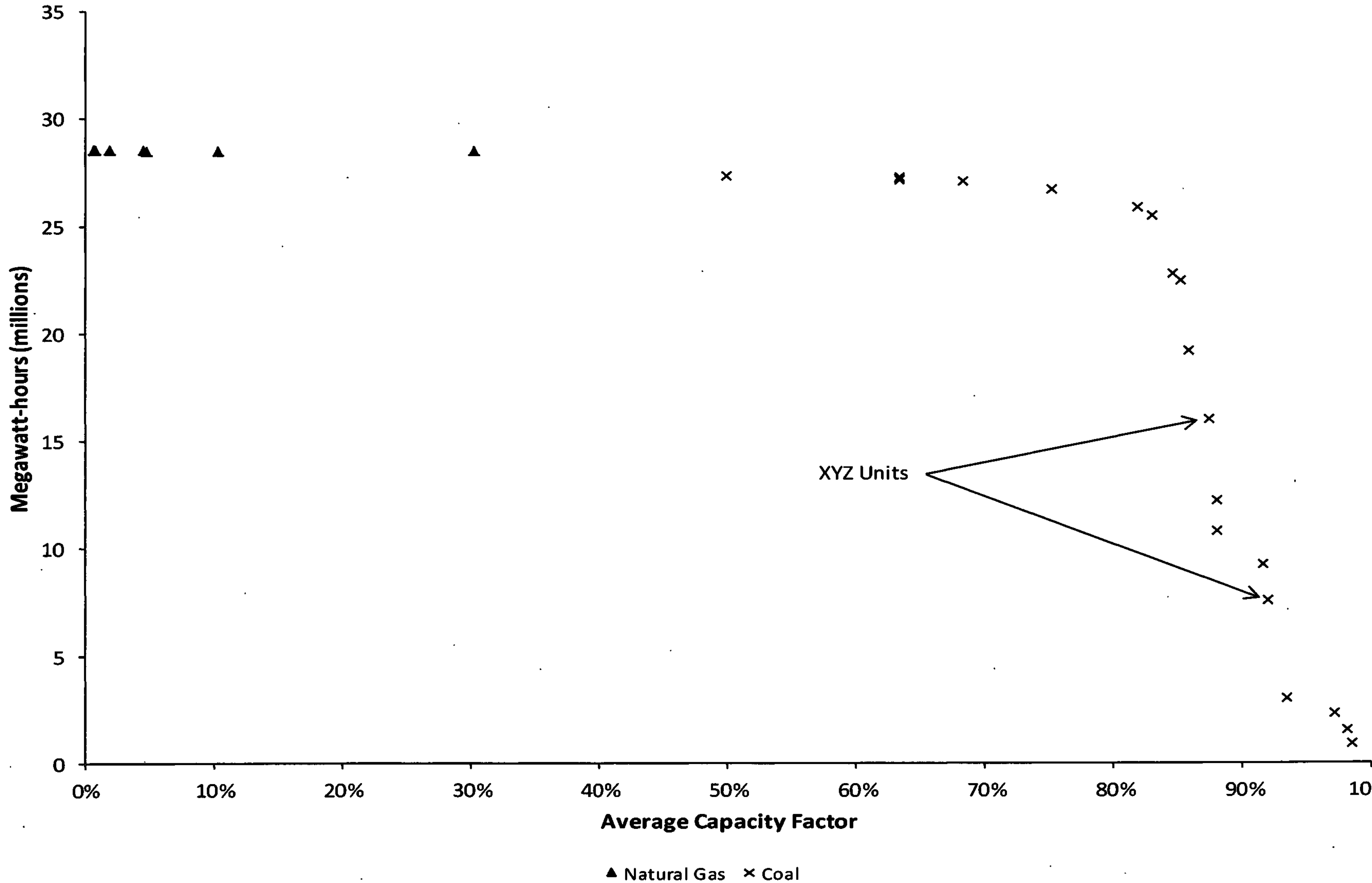

Note: Removed high cost peaking supply for comparability. Supply curve is from September 3, 2012. Total marginal cost of generators modeled by Ventyx as the sum of: fuel cost, variable operations and maintenance cost, total NOx cost, total $SO_2$ cost, total $CO_2$ cost and total mercury cost. Fuel cost sourced from FERC Form 1, EIA-412, RUS-12, EIA-906/923, EIA-423, and Ventyx primary research.

Source: Ventyx

Figure 25A

**CUMULATIVE CONTRIBUTION TO TOTAL PRODUCTION IN XYZ PLANT'S REGION BY CAPACITY FACTOR**

July 2010 – June 2011

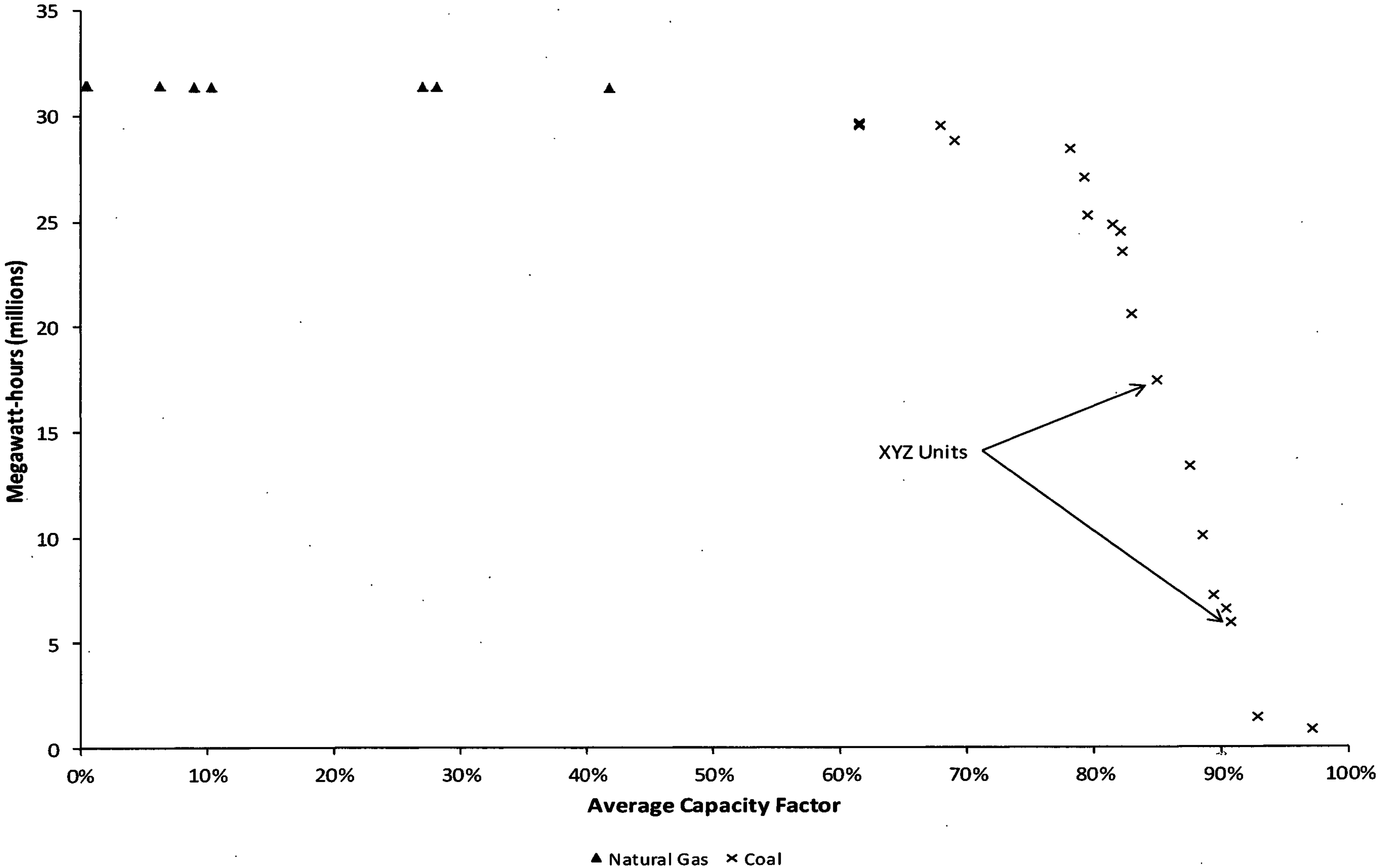



Source: Ventyx, Unit Generation and Emissions – Annual Dataset.

Figure 25B

**CUMULATIVE CONTRIBUTION TO TOTAL PRODUCTION IN XYZ PLANT'S REGION BY CAPACITY FACTOR**

July 2011 – June 2012




Source: Ventyx, Unit Generation and Emissions – Annual Dataset.

rail rates for transportation of coal for electric power generation. While the examples present methods of economic analysis relevant to the issue of market dominance in rail transportation, they are not intended to represent specific tests or screening mechanisms. Nonetheless, utilizing the same underlying data, the analyses in the examples are similar to analyses used regularly by participants in and regulators of the wholesale power markets seeking to understand the competitive position and prospects for a particular generation resource.

Indirect competition remains an important competitive factor that competitively disciplines rail rates in some instances, including the rates for transportation of coal for coal-fired electric power generation at Plant ABC as shown by the above example analyses. Given the importance to shippers and railroads of rail transportation of coal for electric power generation, and the increasing significance of competition in the downstream wholesale power markets in constraining rates for that transportation, the recognition of indirect competition is crucial to accurately identifying market dominance over such movements. The fact that it is now possible to perform the relevant analyses of product and geographic competition for rail transportation of coal to specific coal-fired generation resources utilizing publicly available information should fully address and allay the Board's previous concerns about complexity and undue burden in considering product and geographic competition in market-dominance determinations, at least as applied to rail transportation of coal for coal-fired electric power generation.

## VERIFICATION

I, David Reishus, declare under penalty of perjury, that the foregoing statement is true and correct and that I am qualified and authorized to file this statement.

Executed: November 14, 2012

David Reishus

COMPASS LEXECON

# CURRICULUM VITAE

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**PROFESSIONAL EXPERIENCE**

Compass Lexecon
Boston, MA
*Senior Vice President/Senior Managing Director,* July 1999 - present

The Economics Resource Group, Inc., Cambridge, MA
*President,* 1993 - June 1999
*Senior Economist,* 1990 - 1993

> Provides economic analysis and advice on issues of regulation, antitrust, taxation and applied microeconomics to a variety of clients. Develops, manages, and oversees economic analyses for clients and other principals. Responsible for the management and operations of the company.

U.S. Congress, Joint Committee on Taxation, Washington, DC
*Economist,* 1987 - 1990

> Provided economic analysis and development of legislative tax proposals. Responsibilities included corporate and foreign taxation and proposals related to low-income taxpayers, child care, and health issues.

Harvard University, Cambridge, MA
*Instructor,* 1986 - 1987

> Leader of senior thesis tutorial for industrial organization and finance topics. Previously taught Introductory Economics.

Information Resources, Inc., Chicago, IL
*Consultant*, 1979 - 1980

**EDUCATION**

Harvard University, Cambridge, MA
Ph.D. in Economics, 1988
Dissertation: "Empirical Essays on the Economics of Taxation and the Firm"
M.A. in Economics, 1983

Northwestern University, Chicago, IL
B.A. in Economics, 1979

**TESTIMONY AND OTHER REPORTS**

Modis
*In the United States District Court for the District of Columbia, Case 1:09-cv-01051-RWR, Modis, Inc. v. Infotran Systems, Inc. and Tien H. Tran v. Modis Inc. and Timothy W. Martin.* Expert Report, October 18, 2010. Deposition testimony December 7, 2011.

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*In the Matter of Arbitration No. 91312, Canada v. The United States of America.* Expert Witness Statement of Joseph P. Kalt and David Reishus, May 12, 2009.

Government of Canada
*In the Matter of Arbitration No. 7941, The United States of America v. Canada.* Expert Witness Statement, June 29, 2008. Rebuttal Expert Witness Statement, August 11, 2008. (With Joseph Kalt).

Government of Canada
*In the Matter of an Arbitration Under Chapter Eleven of the North American Free Trade Agreement Between Merrill & Ring Forestry, L.P. and The Government Of Canada.* Expert Report, May 9, 2008. Supplemental Expert Affidavit, March 19, 2009. Oral testimony, May 21, 2009.

Dynegy
*In the Circuit Court of Colbert County, State of Alabama, NO. CV-2003-142JMH, Nelson Brothers, LLC v. Cherokee Nitrogen v. Dynegy Marketing & Trade; Dynegy Inc.* Expert Report, August 22, 2007.

Independent Energy Producers Association of California
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*Producers Association*; Prepared Testimony of David Reishus and Joseph Cavicchi on behalf of the IEPA, March 2, 2007.

First Energy

*Before the Pennsylvania Public Utility Commission, Petition of Metropolitan Edison Company for Approval of a Rate Transition Plan (Metropolitan Edison Company Docket No. R-00061366) and Petition of Pennsylvania Electric Company for Approval of a Rate Transition Plan (Pennsylvania Electric Company Docket No. R-00061367),* Direct Testimony of David A. Reishus, April 10, 2006.

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*In the United States District Court For the District of Columbia, Case No. 02-CV-1773, National Railroad Passenger Corporation v. ExpressTrak, L.L.C.*, Expert Report, Dated January 3, 2006; revised April 7, 2006. Deposition testimony, March 24 and April 26, 2006.

British Columbia Lumber Trade Council and the Province of British Columbia

*Before the International Trade Administration, Department of Commerce, In the Matter of Certain Softwood Lumber Products from Canada (C-122-839). Statement for the First Administrative Review, March 15, 2004 (with Joseph Kalt); Response to Price Impact of Canadian Log Restraints, March 16, 2004 (with Joseph Kalt); Response to Coalition Submission on Pass-Through Issues, April 15, 2004 (with Joseph Kalt); Economics of Arm's-Length Transactions and Subsidy Pass-Through, September 15, 2004 (with Joseph Kalt); Economic Analysis of the Vancouver Log Market, February 28, 2005 (with Joseph Kalt); Comment on the Economic Implications of the Annual Allowable Cut, December 5, 2005 (with Joseph Kalt); Update to Economic Analysis of the Vancouver Log Market, December 5, 2005 (with Joseph Kalt).* Analysis of various aspects of the operation of Canadian timber, log, and lumber markets. Reports filed from March 15, 2004 to December 5, 2005.

Multiple Associations of Energy Producers

*Before the Public Utilities Commission of the State of California, Rulemakings R.04-04-025 – R.04-04-003*, "Prepared Rebuttal Testimony," October 28, 2005 (with A. Joseph Cavicchi). Oral testimony, January 23 and 24, 2006.

PPL Corporation

*United States of America, Before the Federal Energy Regulatory Commission, Docket No. ER05-1416-000*, "Affidavit of A. Joseph Cavicchi, Joseph P. Kalt, Ph.D., and David A. Reishus, Ph.D. on Behalf of the PPL Parties," October 19, 2005.

The Burlington Northern and Santa Fe Railway Company

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Verified Statement, June 3, 2003; Verified Statement, August 4, 2003; Reply Verified Statement, August 29, 2003.

Dynegy Inc.

*United States of America, Before the Federal Energy Regulatory Commission, San Diego Gas & Electric Company v. Sellers of Energy and Ancillary Services, Investigation of Practices of the California ISO and PX; Pub. Utils. Comm'n of the State of California v. Sellers of Long-Term Contracts.* Prepared Rebuttal Testimony (with Patrick Wang), March 20, 2003.

Duke Energy Trading and Marketing LLC

*United States of America, Before the Federal Energy Regulatory Commission, San Diego Gas & Electric Company v. Sellers of Energy and Ancillary Services into Markets Operated by the California Independent System Operator and the California Power Exchange; Investigation of Practices of the California Independent System Operator and the California Power Exchange.* Prepared Rebuttal Testimony (with Patrick Wang), March 20, 2003.

Dynegy Inc.; Duke Energy Services LLC; Mirant Americas, Inc.; Reliant Energy; Williams Energy Marketing and Trading Co.

*United States of America, Before the Federal Energy Regulatory Commission, San Diego Gas & Electric Company v. Sellers of Energy and Ancillary Services into Markets Operated by the California Independent System Operator and the California Power Exchange; Investigation of Practices of the California Independent System Operator and the California Power Exchange.* Affidavit (with Patrick Wang), October 15, 2002 (revised November 12, 2002), analyzing operation of California natural gas markets during the October 2000 through June 2001 period encompassed by the California Refund Proceeding.

Association of American Railroads

*Review of Rail Access and Competition Issues* (with Joseph P. Kalt), March 26, 1998, *Before the Surface Transportation Board, Ex Parte No. 575.* Joint Verified Statement evaluating the economic effect of existing regulation on U.S. railroads and analyzing the implications of competitive access regulation.

Crow Tribe of Indians

*Report Concerning the Crow Tribe Resort Tax* (with Joseph P. Kalt), November 27, 1996; *Surrebuttal Report Concerning the Crow Tribe Resort Tax* (with Joseph P. Kalt), February 25, 1997; and *Report Concerning the Crow Tribe Resort Tax* (with Joseph P. Kalt), March 31, 2000. Reports analyzing the economic relationship of proposed resort tax and tribal spending activities on reservation economy in connection with Rose vs. Adams in the Crow Tribal Court, Montana.

Sithe Energies

*Economic Impact on New York State of the Sithe Plan*, Chapter IV of *Energizing New York: The Sithe Plan*, December 8, 1995. Report analyzing the regional economic impact of electric and gas restructuring proposals.

Massachusetts Department of Environmental Protection

*Use of an Economic Test for Distinguishing Legitimate Recycling Activities*, July 1993. Report for Department's use in analyzing the licensing of proposed hazardous waste recycling facility.

**PUBLICATIONS AND RESEARCH**

"Corporate Reorganizations: Tax Treatment of Corporate Mergers, Acquisitions, and Reorganizations," *The Encyclopedia of Taxation and Tax Policy, 2nd ed.*, The Urban Institute Press, 2006. (Revised and updated.)

"Corporate Reorganizations: Tax Treatment of Corporate Mergers, Acquisitions, and Reorganizations," *The Encyclopedia of Taxation and Tax Policy*, The Urban Institute Press, 1999.

"Outside Directorships, the Reputation of Managers, and Corporate Performance" (with S. Kaplan), *Journal of Financial Economics*, Vol. 27, No. 2, September 1990.

"Financing Child Care: Who Will Pay for the Kids?," *National Tax Journal*, Vol. XLII, No. 3, September, 1989.

"The Effects of Taxation on the Merger Decision" (with A. Auerbach), in A. Auerbach, ed., *Corporate Takeovers: Causes and Consequences*, University of Chicago Press, 1988.

"Taxes and the Merger Decision" (with A. Auerbach), in J. Coffee, L. Lowenstein, and S. Rose-Ackerman, eds., *Knights, Raiders and Targets*, Oxford University Press, 1988.

"The Impact of Taxation on Mergers and Acquisitions" (with A. Auerbach), in A. Auerbach, ed., *Mergers and Acquisitions*, University of Chicago Press, 1988.

## OTHER PROFESSIONAL ACTIVITIES

Presentations to National Bureau of Economic Research, Federal Reserve Bank of Cleveland, Federal Reserve Bank of New York, Harvard University, Tax Economists Forum, National Tax Association, Western Economic Association, The Institute for Energy Law of The Center for American and International Law.

Memberships in National Tax Association, American Economic Association.

Referee for *Quarterly Journal of Economics*, *Journal of Law and Economics*.

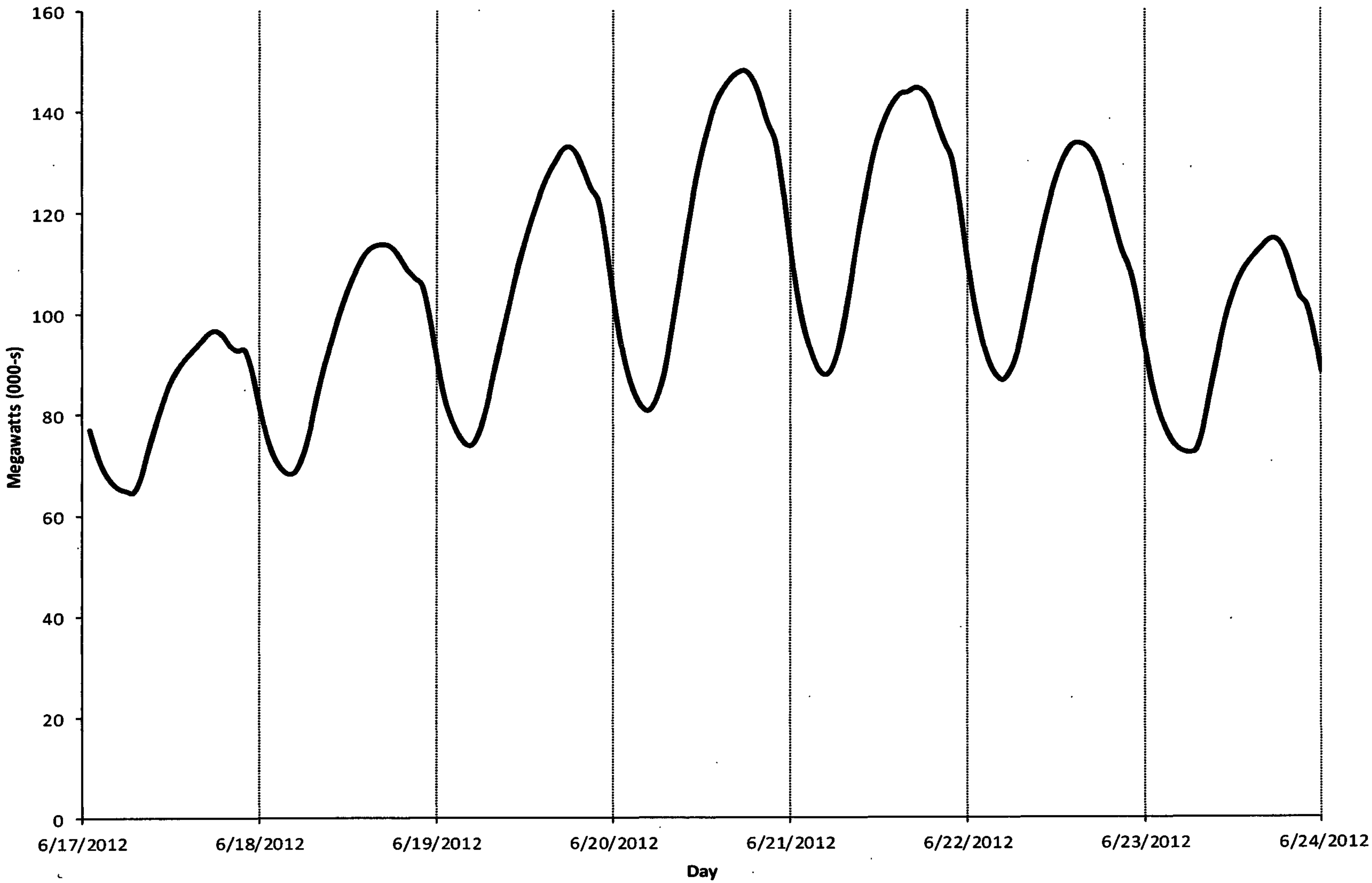
## HONORS AND AWARDS

National Science Foundation Fellowship, 1981-1985.
International Foundation of Employee Benefit Plans, Graduate Research Fellowship, 1984.
Phi Beta Kappa, 1979.

Figure 1

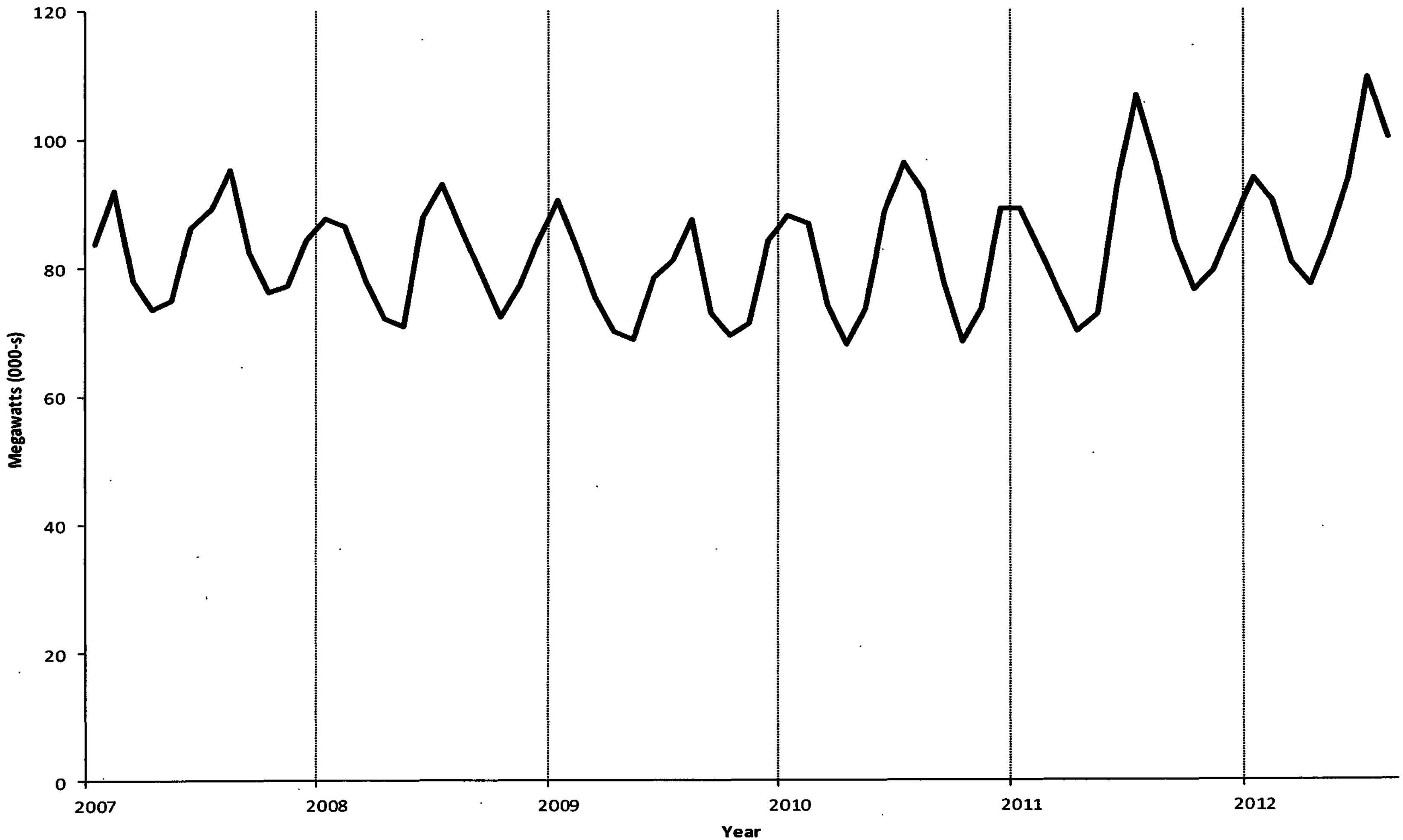
## ELECTRICITY DEMAND VARIES SUBSTANTIALLY THROUGHOUT THE DAY

PJM Hourly Load




Note: Week of June 17th 2012. Vertical lines represent midnight for each respective day.
Source: Ventyx, ISO Total Load Dataset.

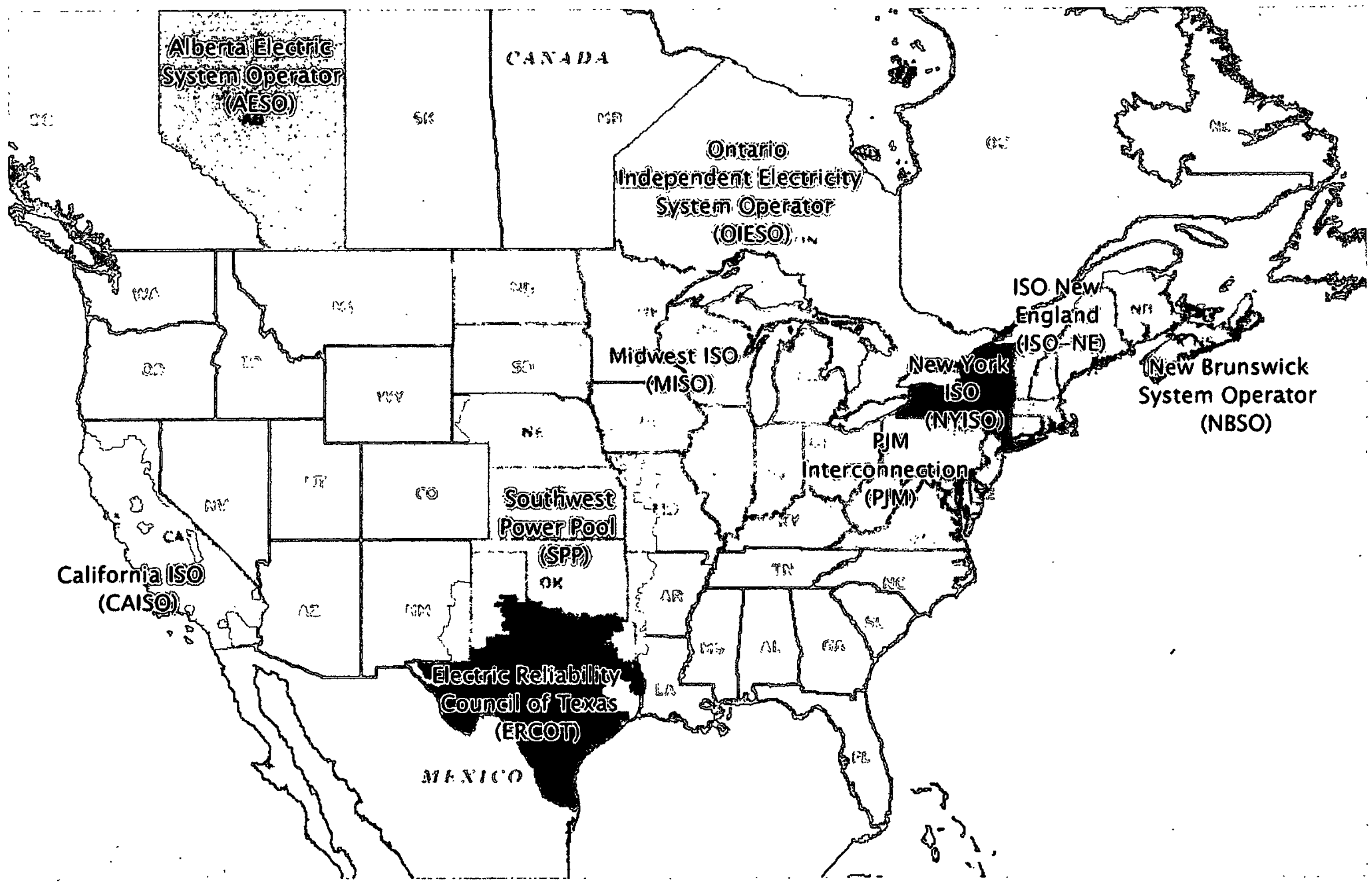
Figure 2
**ELECTRICITY DEMAND VARIES ACROSS SEASONS**
PJM Average Hourly Load by Month




Note: Vertical lines represent the first day of each respective year. Data spans from January 2007–August 2012.
Source: Ventyx, ISO Total Load Dataset.

Figure 3

## REGIONS OF INDEPENDENT SYSTEM OPERATORS

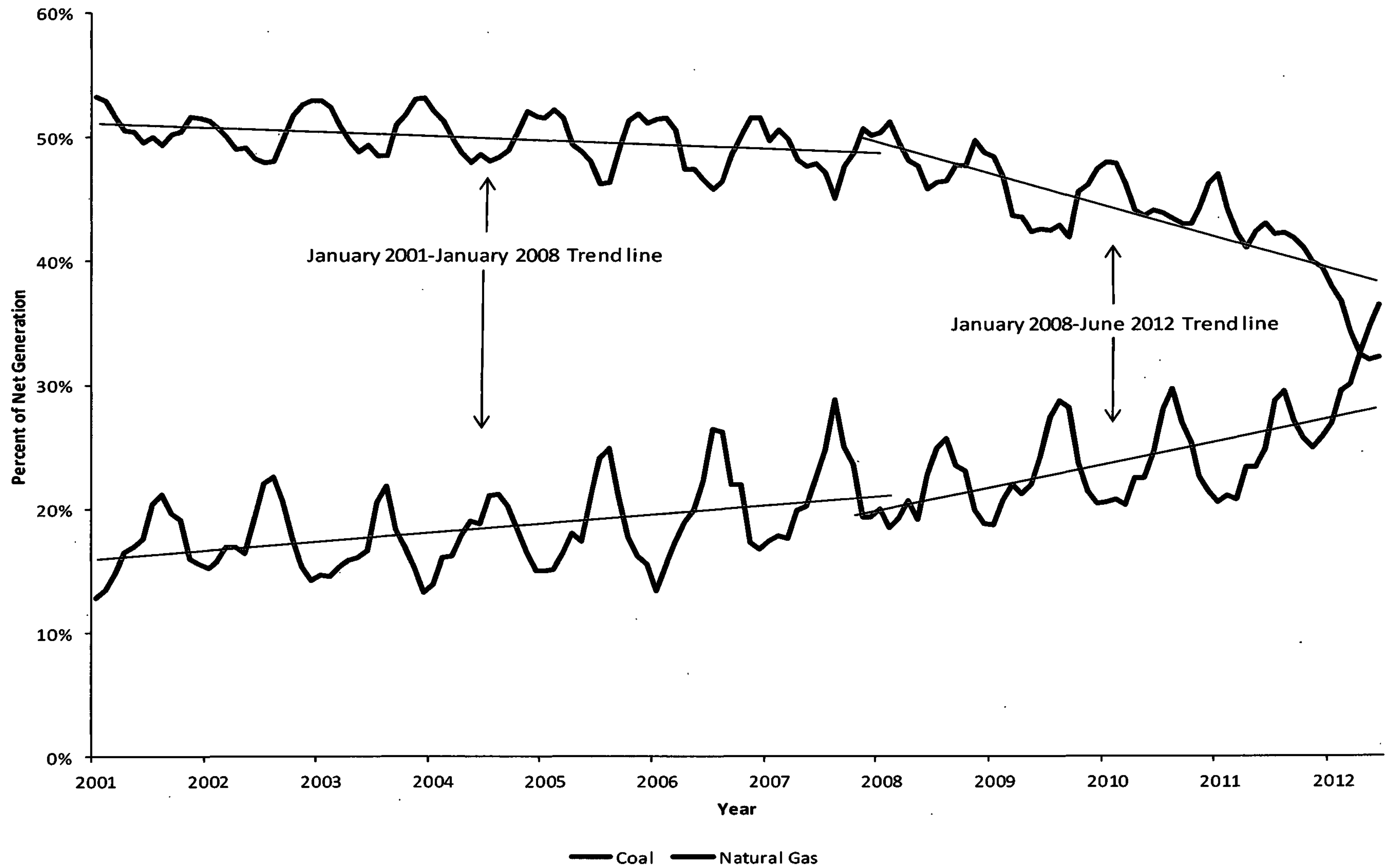



Note: Map current as of April 2012.
Source: FERC

Figure 4

## SHARE OF U.S. POWER GENERATION: COAL v. NATURAL GAS

January 2001–June 2012

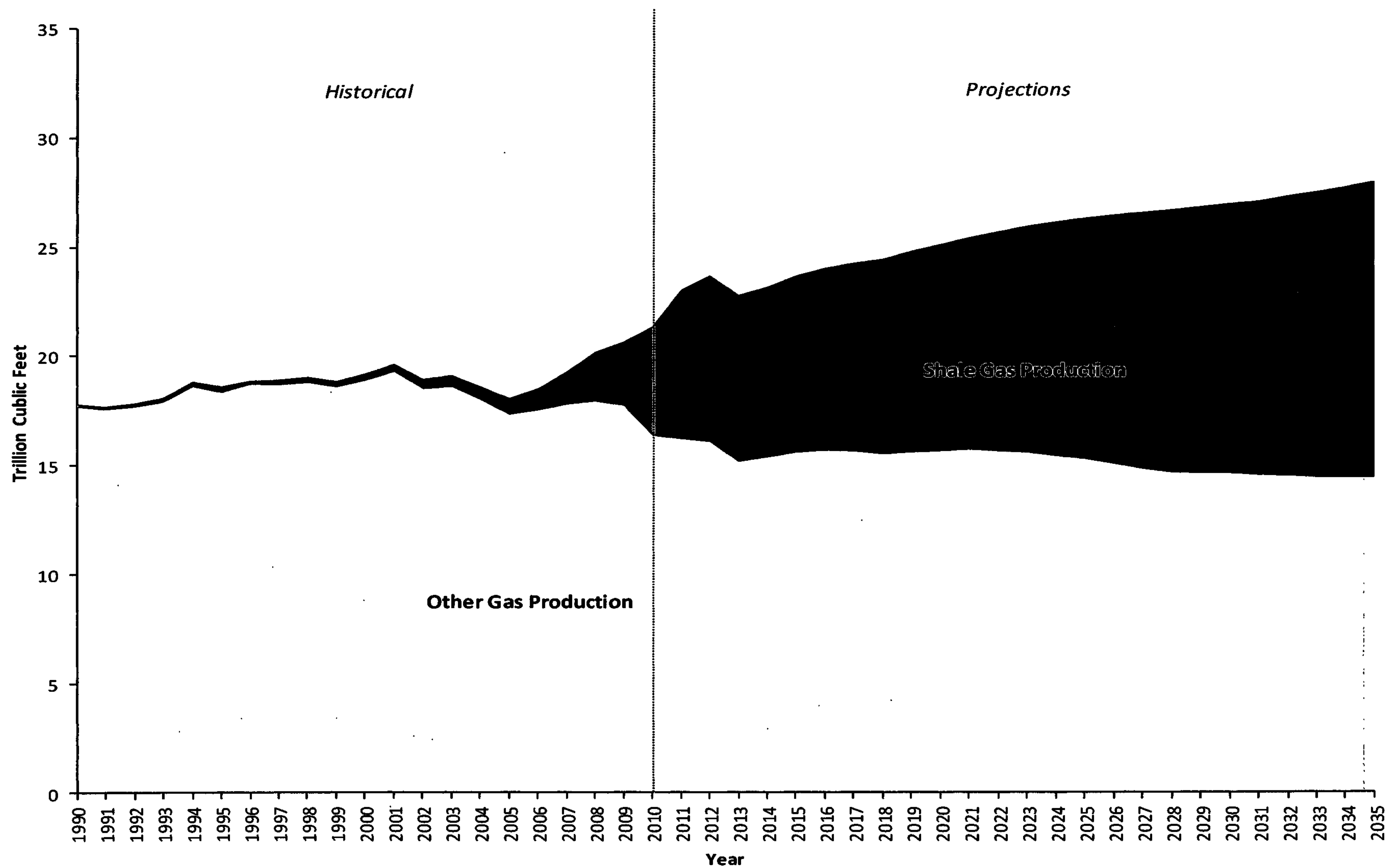



Source: U.S. Energy Information Administration, Electricity Data Browser, Net Generation Dataset.

Figure 5

**U.S. PRODUCTION OF NATURAL GAS**

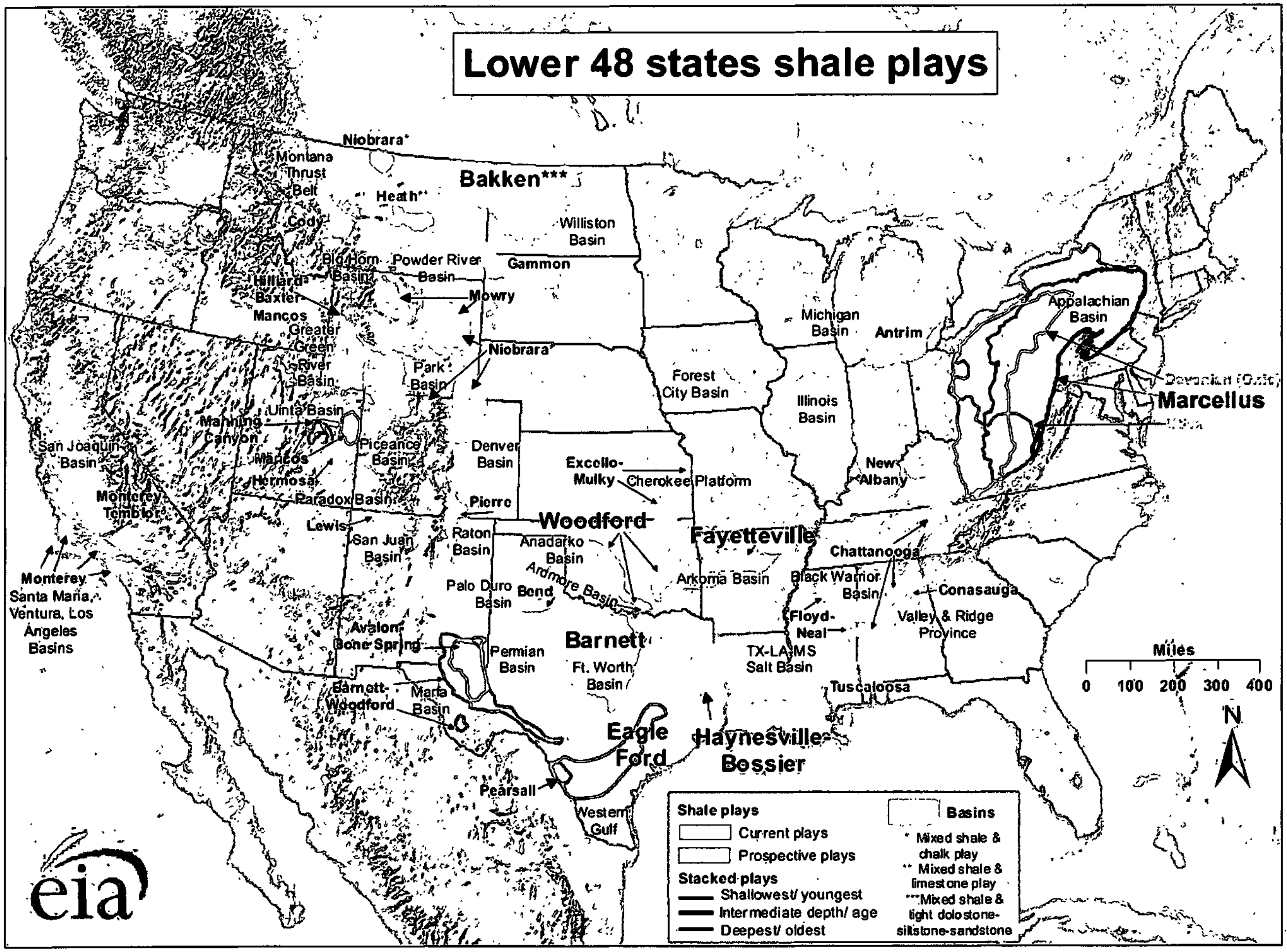
1990-2035




Source: U.S. Energy Information Administration, Annual Energy Outlook 2012.

Figure 6

**MAJOR SHALE GAS AREAS**

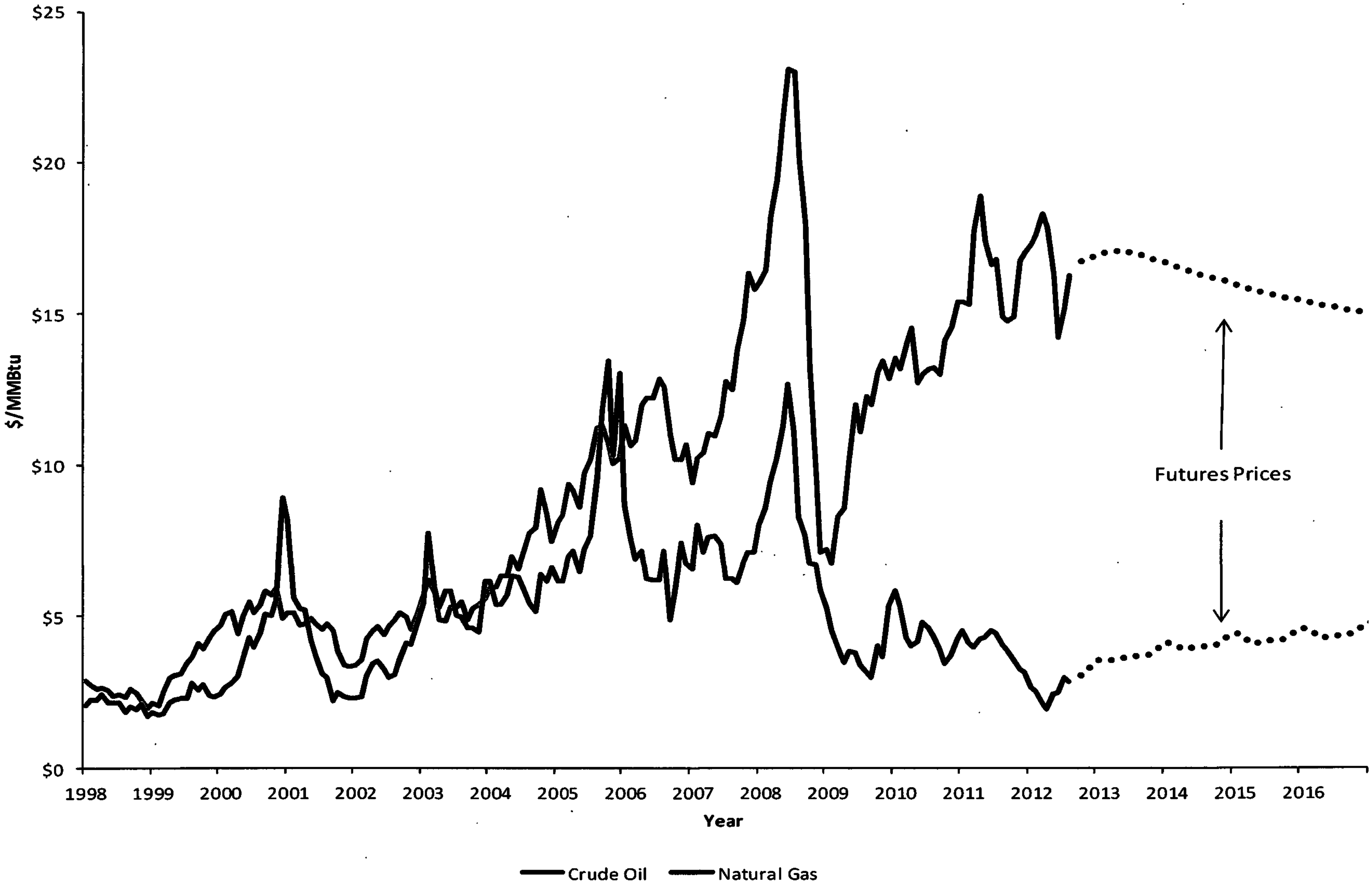



Source: U.S. Energy Information Administration

Figure 7

## U.S. NATURAL GAS PRICES NO LONGER TRACK CRUDE OIL PRICES

January 1998–December 2016

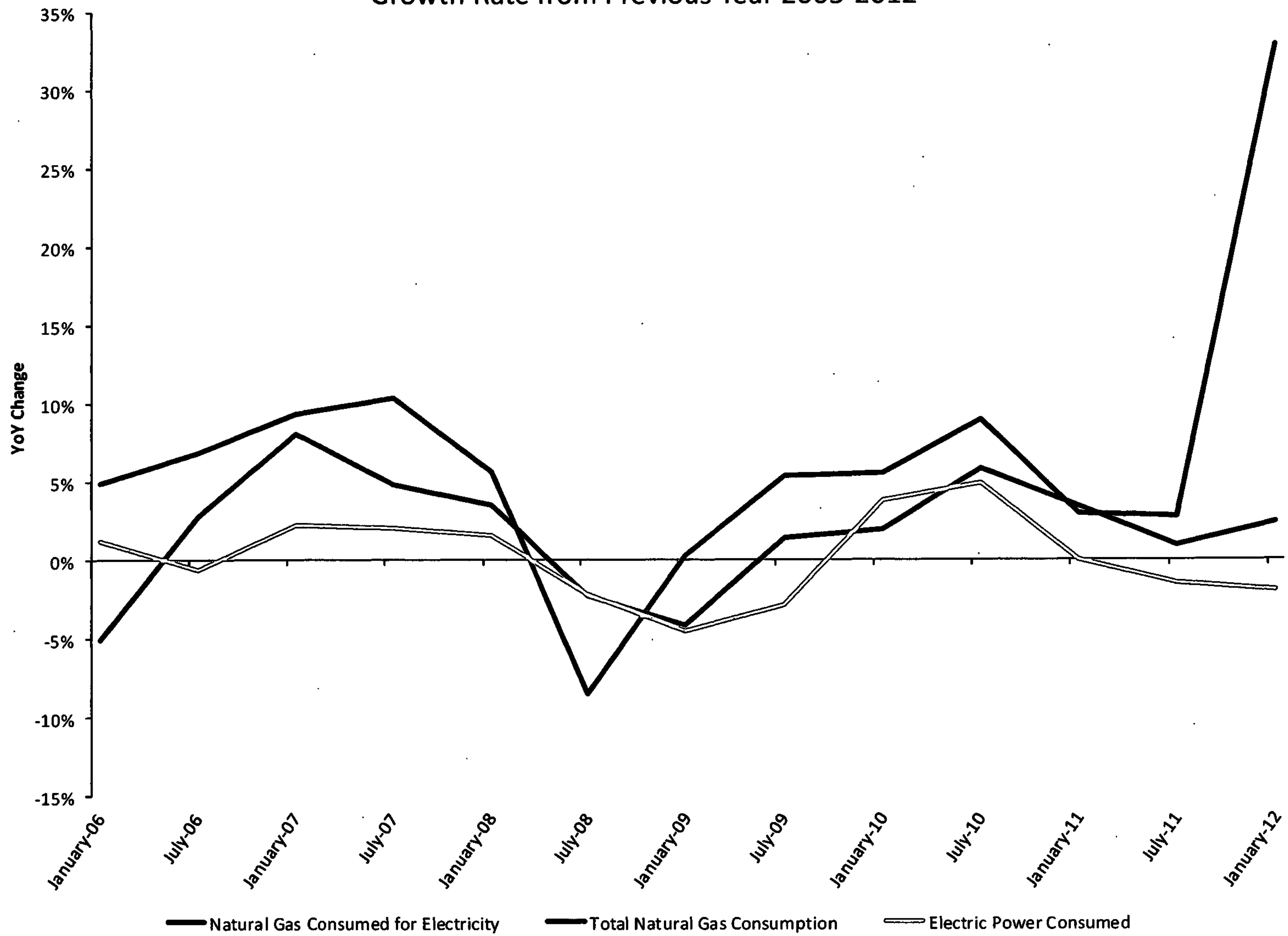



Note: Average monthly price shown. Price of Crude Oil converted to $/MMBtu. 5.8 million Btu per barrel Crude Oil. Gas and Crude Oil futures prices are Henry Hub Natural Gas futures and Light Sweet Crude Oil futures, respectively. Contract futures prices from September 12, 2012 trade date.
Source: U.S. Energy Information Administration. Ventyx, NYMEX and ClearPort Futures Dataset.

Figure 8

## GROWTH IN NATURAL GAS CONSUMED FOR ELECTRIC POWER PRODUCTION

Growth Rate from Previous Year 2005-2012

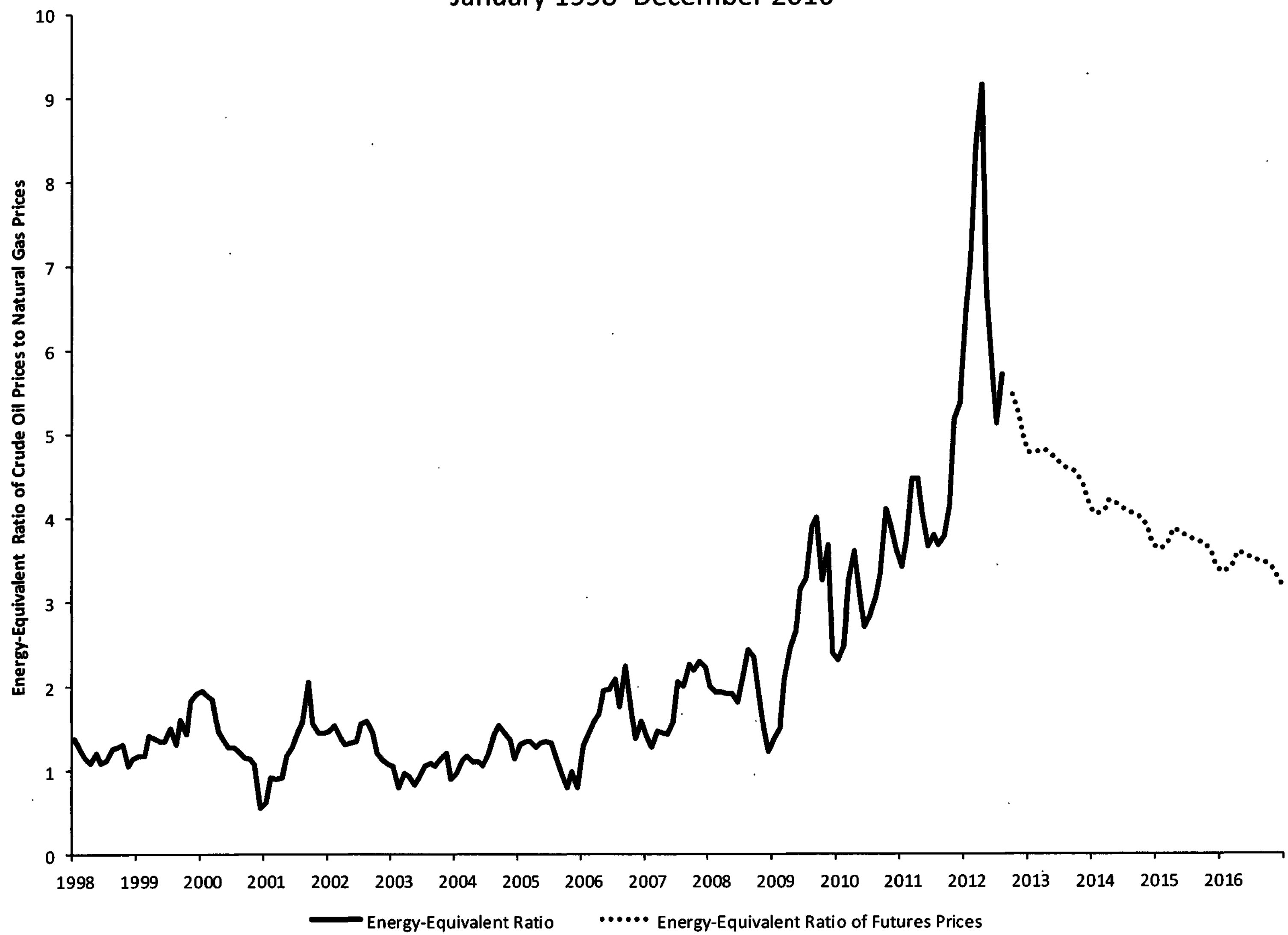



Note: Percentages show changes from the corresponding period in the previous year. Original gas consumption is recorded in thousand MMcF. Original electricity consumption is recorded in million kilowatt-hours.
Source: U.S. Energy Information Administration, Annual Energy Outlook 2012.

Figure 9

## CRUDE OIL PRICES HAVE INCREASED RELATIVE TO NATURAL GAS PRICES

January 1998–December 2016




Note: Figure 9 shows a ratio of average monthly prices. Price of Crude Oil converted to \$/MMBtu. 5.8 million Btu per barrel Crude Oil. Gas and Crude Oil futures prices are Henry Hub Natural Gas futures and Light Sweet Crude Oil futures, respectively. Contract futures prices from September 12, 2012 trade date.
Source: U.S. Energy Information Administration. Ventyx, NYMEX and ClearPort Futures Dataset.

Figure 10

**U.S. NATURAL GAS PROVEN RESERVES**

2006-2010

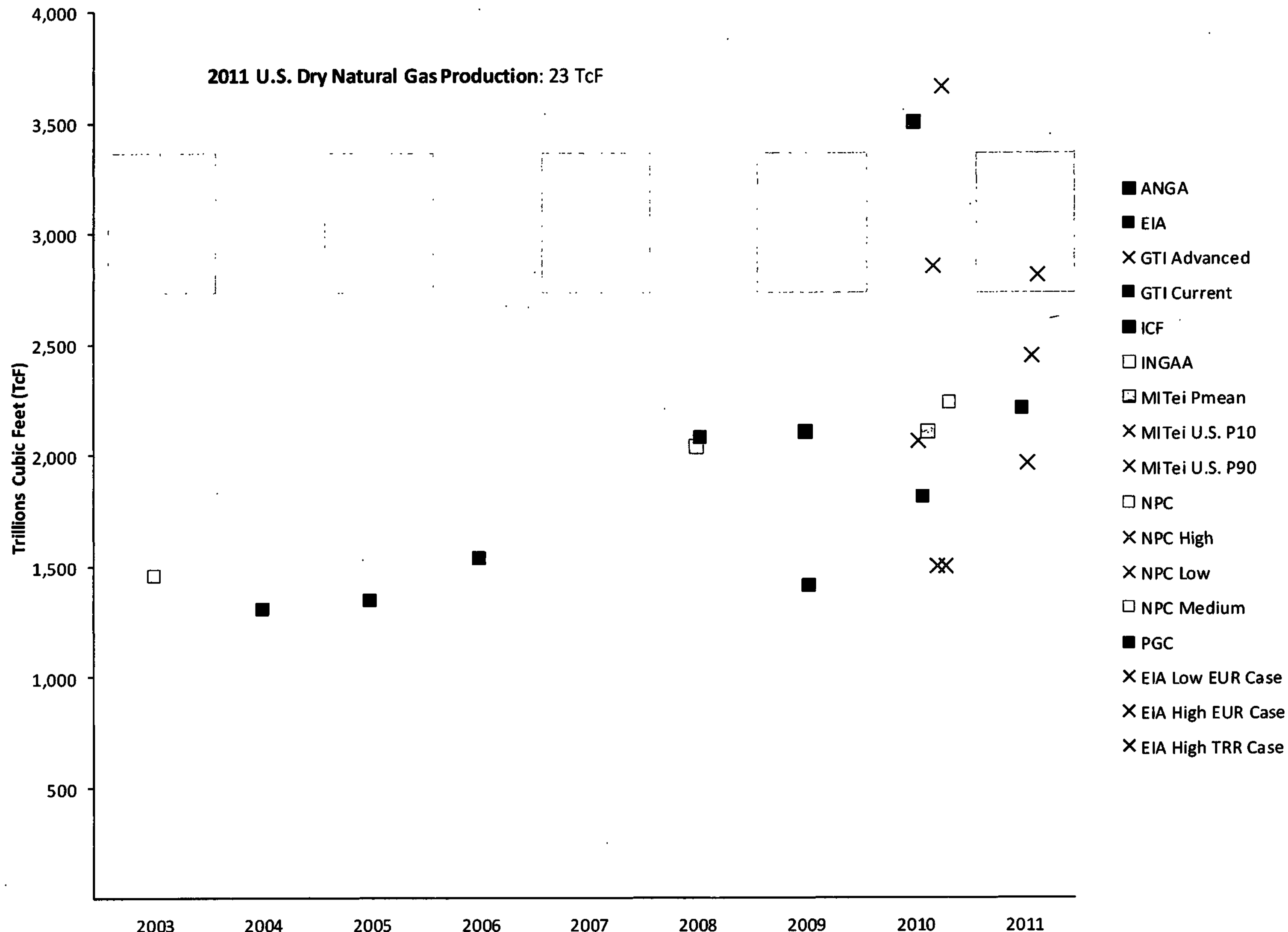
| | Shale (TcF) | Other (TcF) | Total (TcF) |
|---|---|---|---|
| 2006 | 14 | 206 | 220 |
| 2007 | 23 | 224 | 248 |
| 2008 | 34 | 221 | 255 |
| 2009 | 61 | 223 | 284 |
| 2010 | 97 | 220 | 318 |

Source: U.S. Energy Information Administration, U.S. Crude Oil, Natural Gas, and NG liquids Proved Reserves Dataset, Released Data August 1, 2012.

Figure 11

**ESTIMATE OF TECHNICALLY RECOVERABLE U.S. NATURAL GAS RESOURCES BY YEAR IN WHICH ESTIMATE IS CREATED**

2003-2010




Note: Shows estimates of technically recoverable reserves using a number of different methods. ANGA is the America's Natural Gas Alliance; the EIA is the Energy Information Administration; GTI is the Gas Technology Institute; ICF is ICF International; INGAA stands for the Interstate Natural Gas; Association of America; MITei is the Energy Institute at Massachusetts Institute of Technology; NPC is the National Petroleum Council; PGC stands for the Potential Gas Committee.

Source: U.S. Energy Information Administration; National Petroleum Council, "Crude Oil and Natural Gas Resources and Supply," Table 1-16.

Figure 12

## PROJECTION OF U.S. NATURAL GAS PRODUCTION

2015 and 2025

| Source and Case | | 2015 (TcF) | 2025 (TcF) |
|---|---|---|---|
| EIA Cases | *Reference* | 23.7 | 26.3 |
| | *High EUR* | 24.4 | 27.8 |
| | *Low EUR* | 22.8 | 24.3 |
| | *High TRR* | 26.5 | 30.9 |
| **IHSGI** | | 23.8 | 27.2 |
| **EVA** | | 23.8 | 26.7 |
| **Deloitte** | | 24.5 | 27.3 |
| **Seer** | | 23.7 | 25.9 |
| **ExxonMobil** | | 24.0 | 27.0 |
| **INFORUM** | | 24.3 | 27.6 |

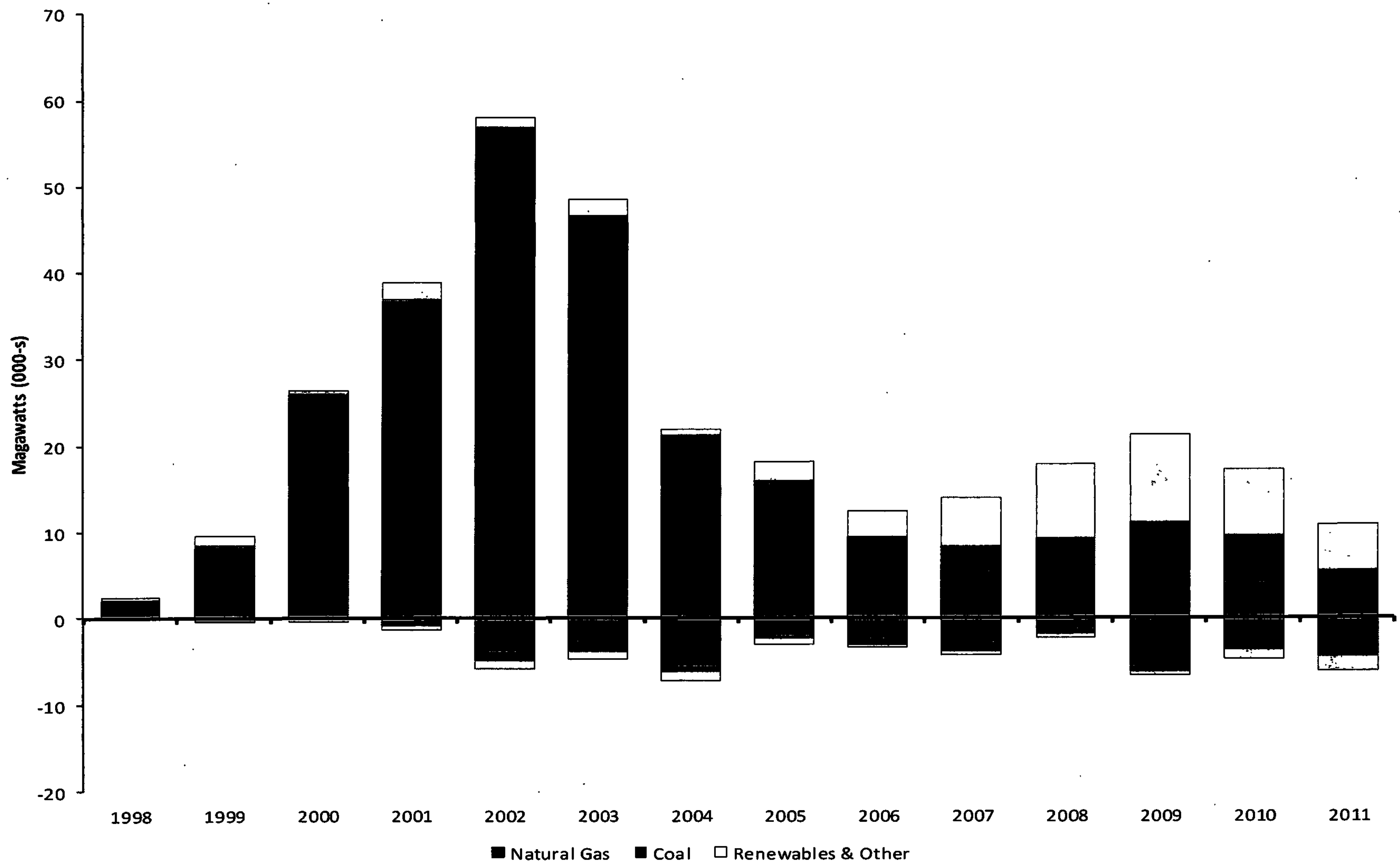
**Note:** 2010 dry natural gas production = 21.6 TcF

Note: Projections developed prior to availability of 2011 data. The High and Low EUR and the High TRR estimates are calculated by the EIA to examine the uncertainty associated with estimating technically recoverable natural gas resources. These estimates adjust the estimated ultimate recovery (EUR) per well and the well spacing assumed in the reference case.
Source: U.S. Energy Information Administration, Annual Energy Outlook 2012.

Figure 13

## ELECTRIC GENERATION CAPACITY ADDITIONS AND RETIREMENTS BY FUEL SOURCE

1998-2010

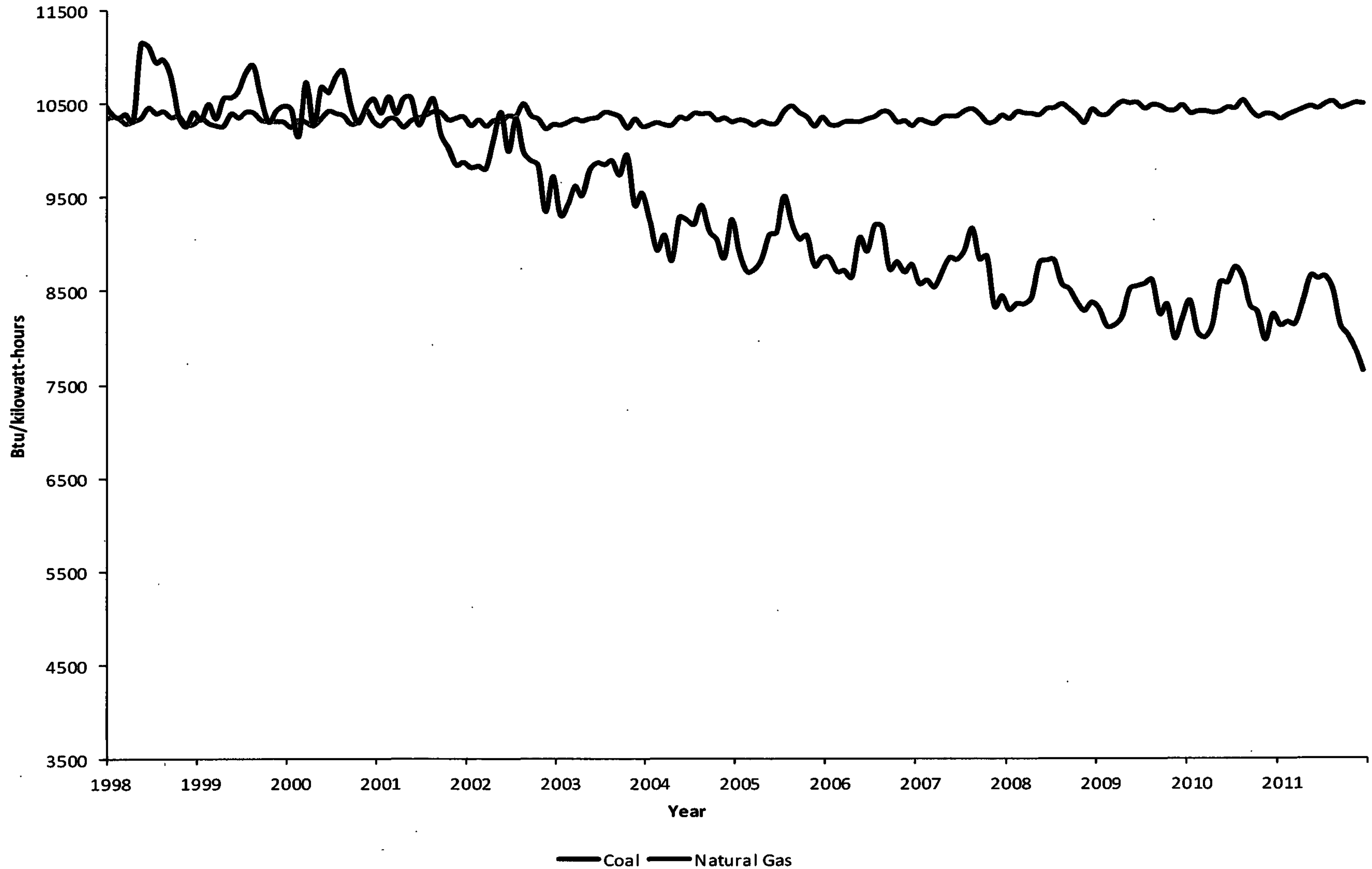



Note: EIA capacity retirements data are unavailable for 1998. Positive megawatts indicate capacity additions, and negative megawatts indicate capacity retirements. Electric generation capacity addition by Natural Gas for years 1998-2010 contains nominal amounts of addition by Oil. 2011 is produced from early release data that have not yet validated. The early release data Includes approximately 20,000 operating and proposed generators. A small number are excluded pending data validation.
Source: U.S. Energy Information Administration, Annual Energy Outlook 2011. U.S. Energy Information Administration, Utility Plants 1999. Energy Information. U.S. Energy Information Administration, Form EIA – 860, "Annual Electric Generator Report."

Figure 14

**AVERAGE ELECTRIC GENERATION HEAT RATE BY FUEL TYPE**

January 1998–August 2011

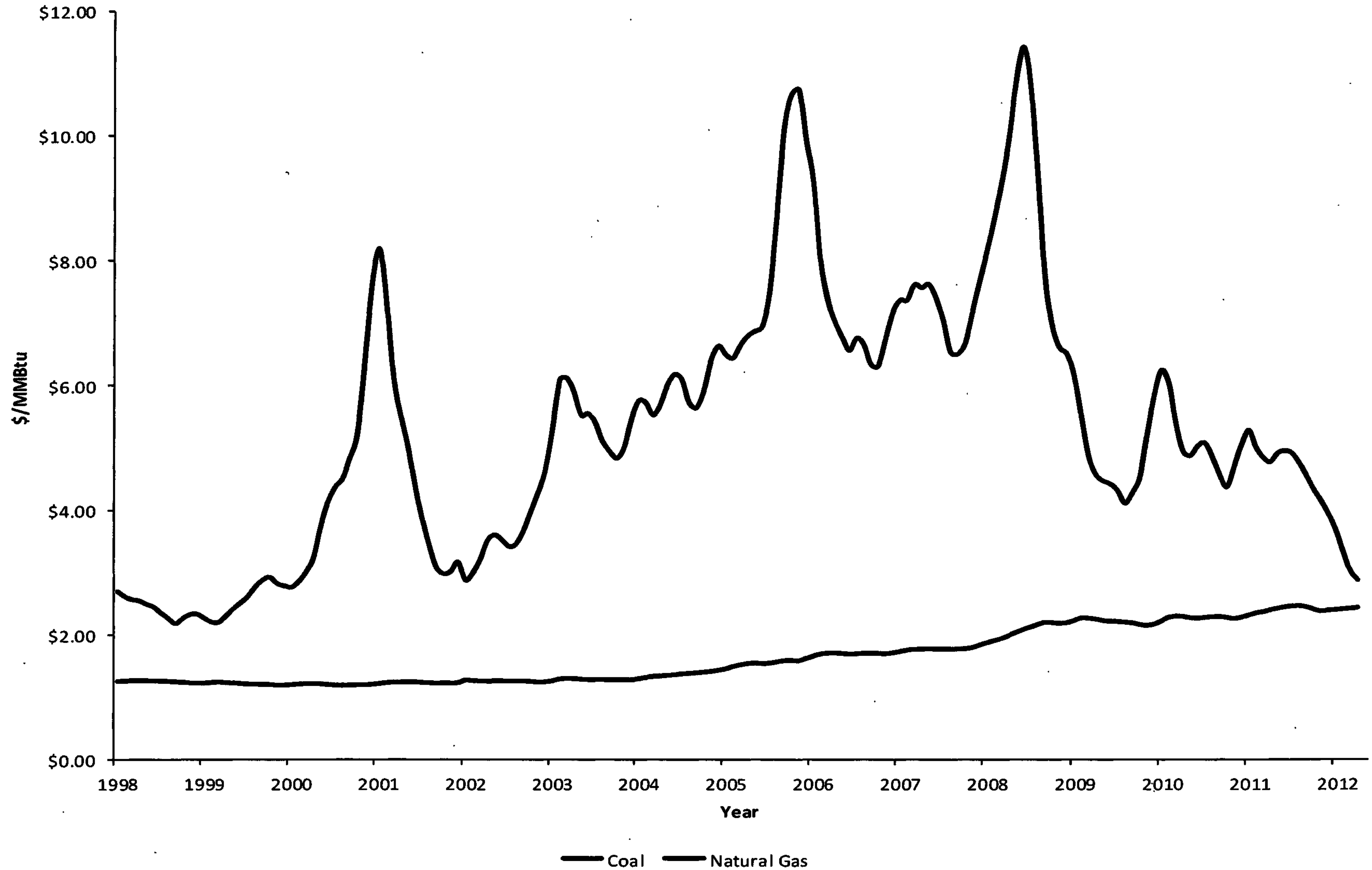



Note: Heat rate is based upon plant operation, maintenance and fuel costs reported in the FERC Form 1, EIA-412 or RUS-12.
Source: Ventyx, Unit Generation and Emissions Dataset.

Figure 15

## COST OF DELIVERED FUEL TO THE ELECTRIC POWER INDUSTRY
## NATURAL GAS v. COAL

January 1998–May 2012

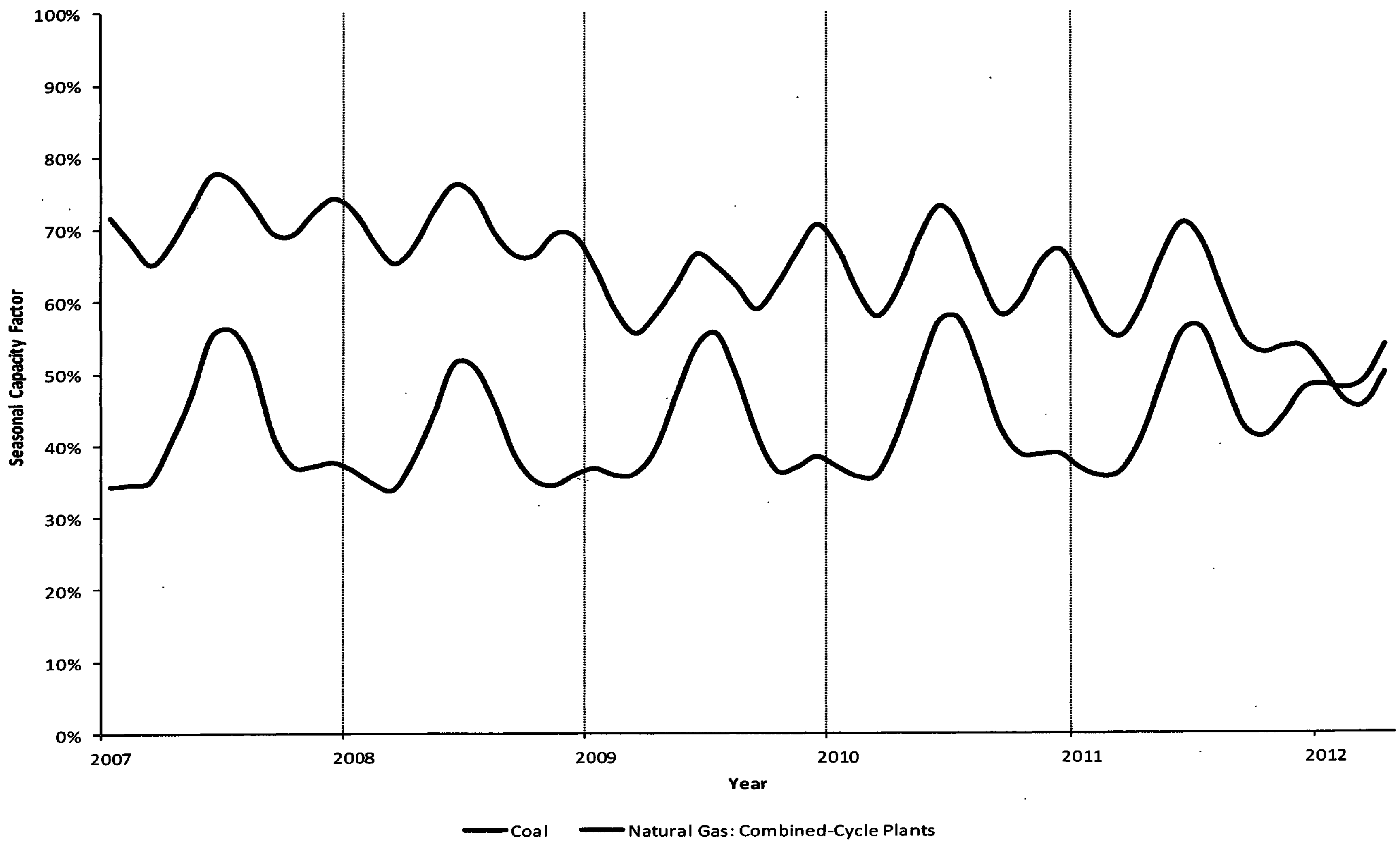



Note: Figure 15 shows a three Month centered moving average price. Dollars per MMBtu includes taxes.
Source: U.S. Energy Information Administration, August 2012 Monthly Energy Review.

Figure 16

**CAPACITY UTILIZATION: COAL-FIRED v. NGCC GENERATION**

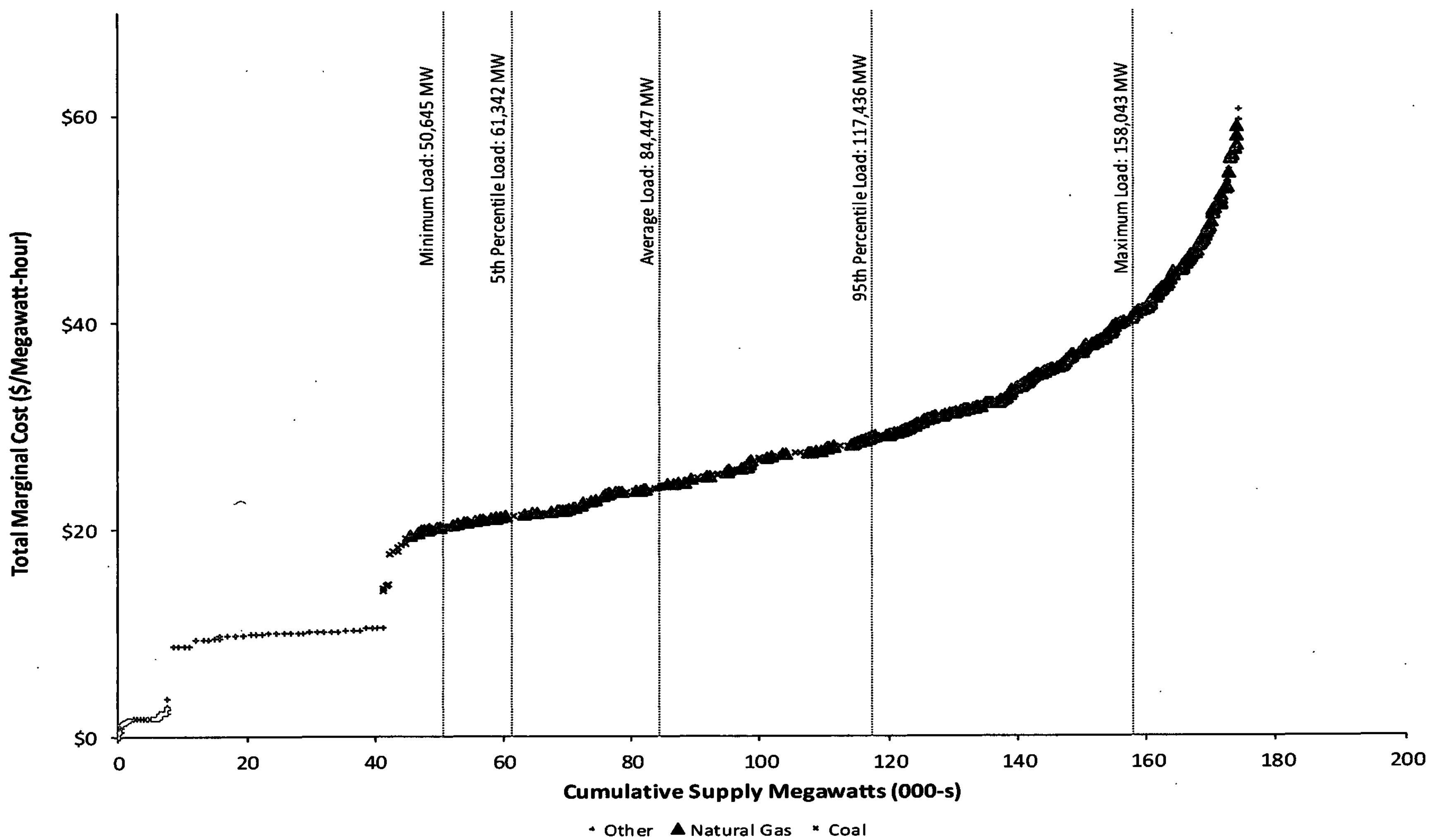
2007-2012




Notes: Seasonal Capacity Factor (%) uses the appropriate Summer/Winter capacity depending on the month. The months of June-September are considered Summer months and the months of October-May are considered Winter months.
Source: Ventyx, Monthly Plant Production Cost Dataset.

Figure 17

**ELECTRIC POWER SUPPLY CURVE: PJM BY FUEL TYPE**

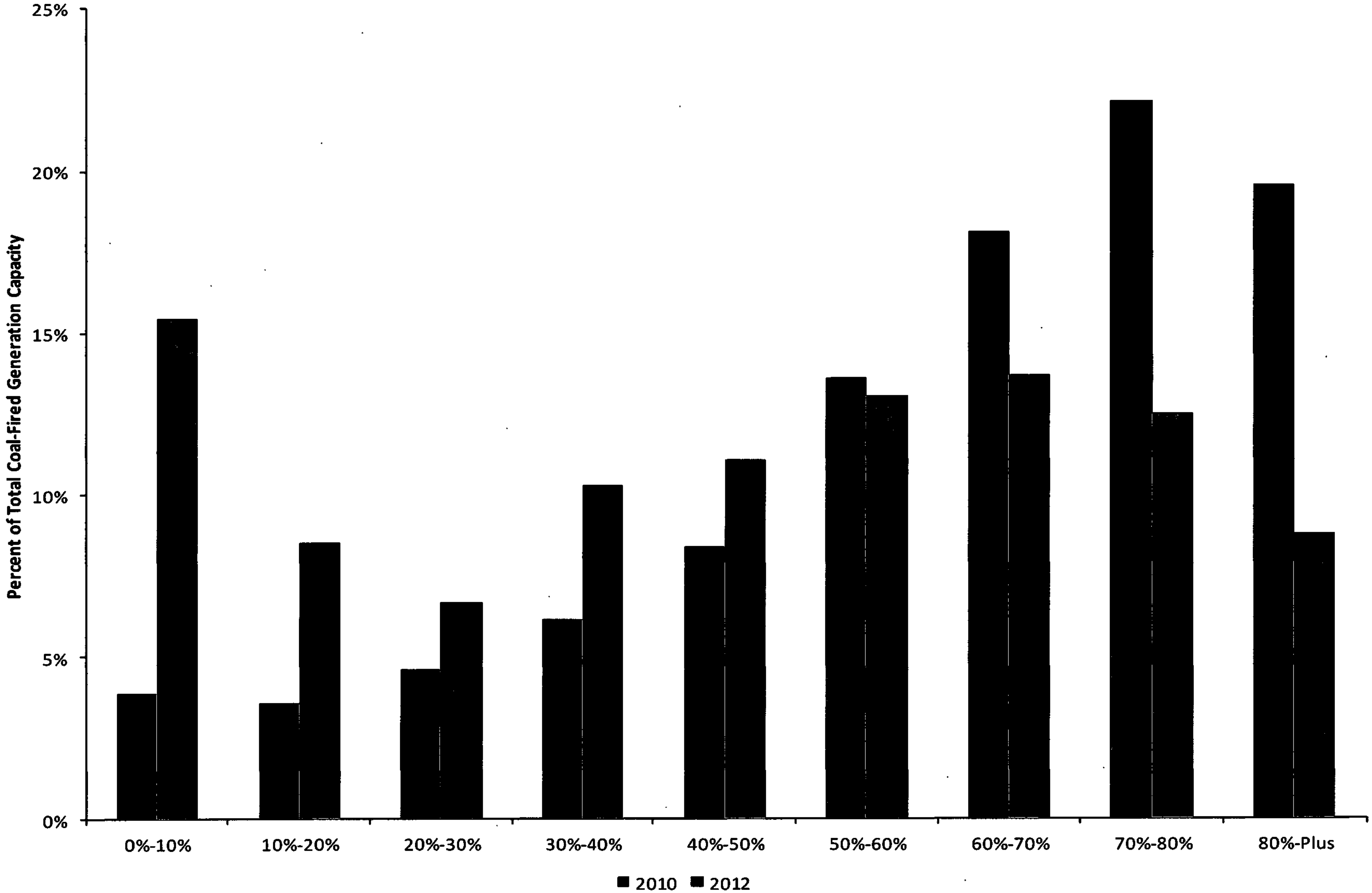



Note: Removed high cost peaking supply for comparability. PJM supply curve is from September 3, 2012. Total marginal cost of generators modeled by Ventyx as the sum of: fuel cost, variable operations and maintenance cost, total NOx cost, total $SO_2$ cost, total $CO_2$ cost and total mercury cost. Fuel cost sourced from FERC Form 1, EIA-412, RUS-12, EIA-906/923, EIA-423, and Ventyx primary research.

Source: Ventyx

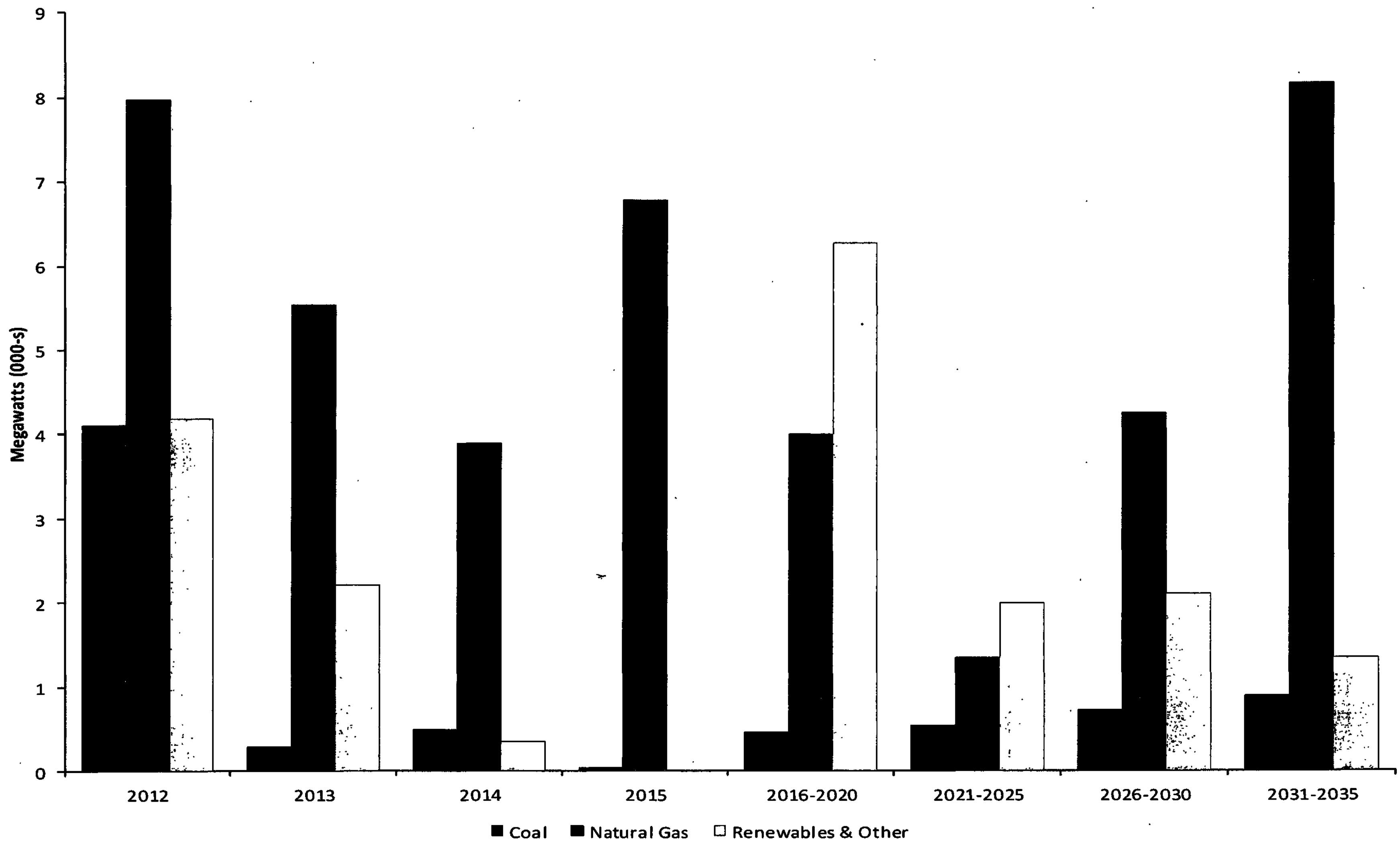
Figure 18

## CAPACITY UTILIZATION OF COAL-FIRED GENERATION HAS DECLINED




Note: Year 2012 is a partial year. Data available for the first six months.
Source: Ventyx, Unit Generation and Emission Dataset.

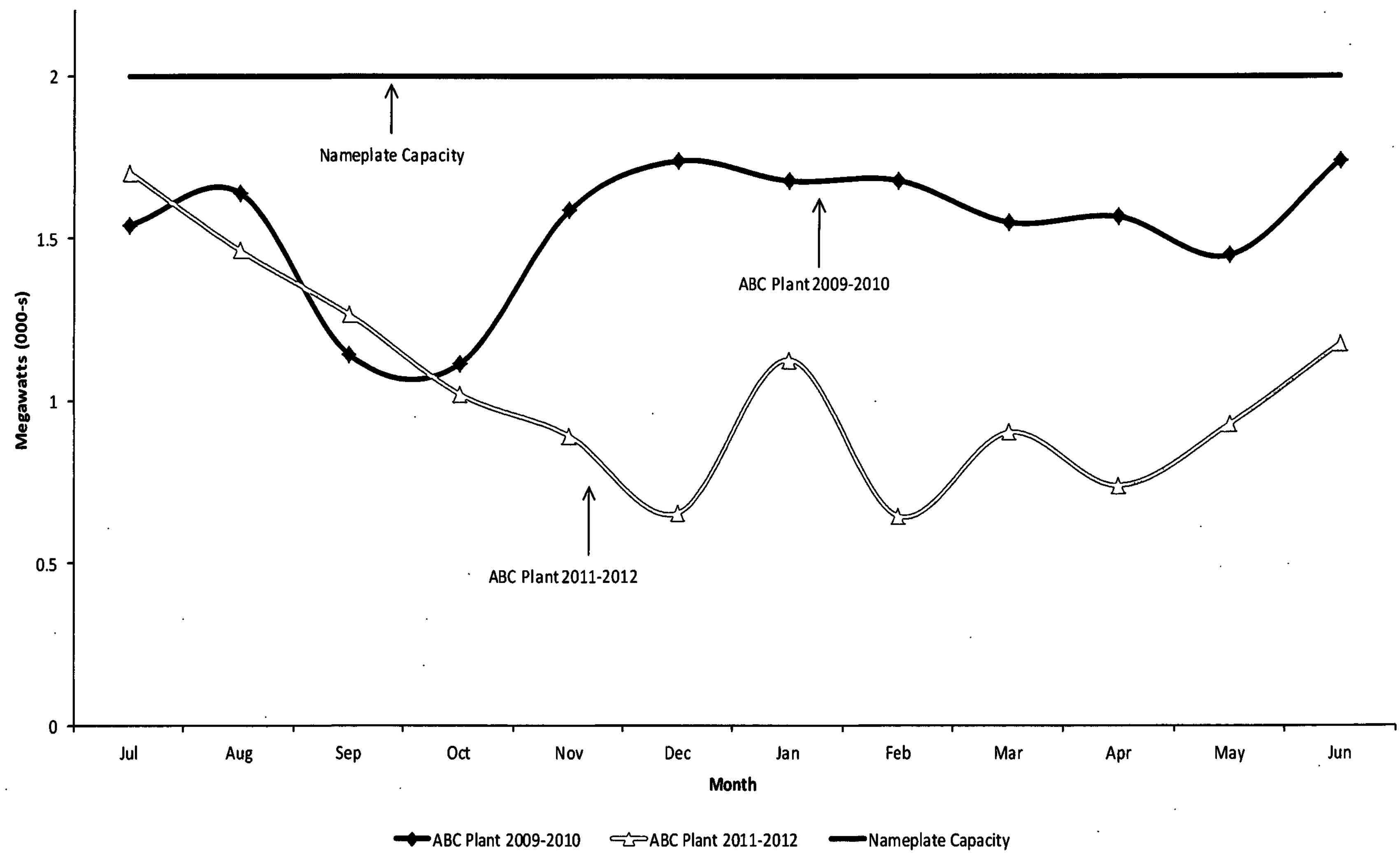
Figure 19
## PROJECTED ELECTRIC GENERATION CAPACITY ADDITIONS BY FUEL TYPE
2011-2035




Note: Projections provided by U.S. Energy Information Administration. Projections across five-year period, after year 2015 projection, are annualized.
Source: U.S. Energy Information Administration, Electric Power Annual 2010, Release Date: November, 2011. U.S. Energy Information Administration, Annual Energy Outlook 2011.

Figure 20

## AVERAGE HOURLY PRODUCTION: ABC PLANT

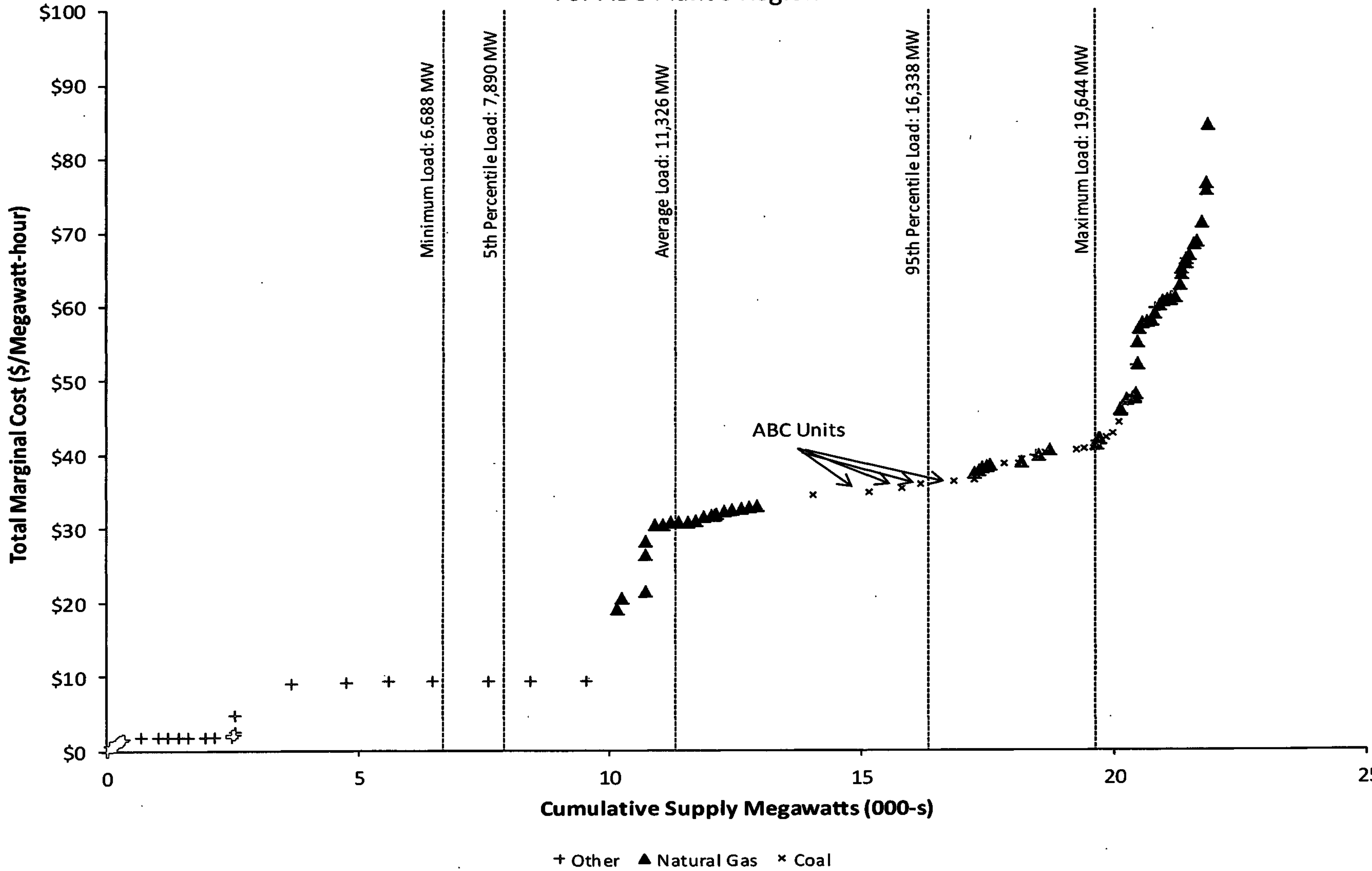



Source: Ventyx, Unit Generation and Emissions Dataset.

Figure 21

**ELECTRIC POWER SUPPLY CURVE BY FUEL TYPE**

For ABC Plant's Region



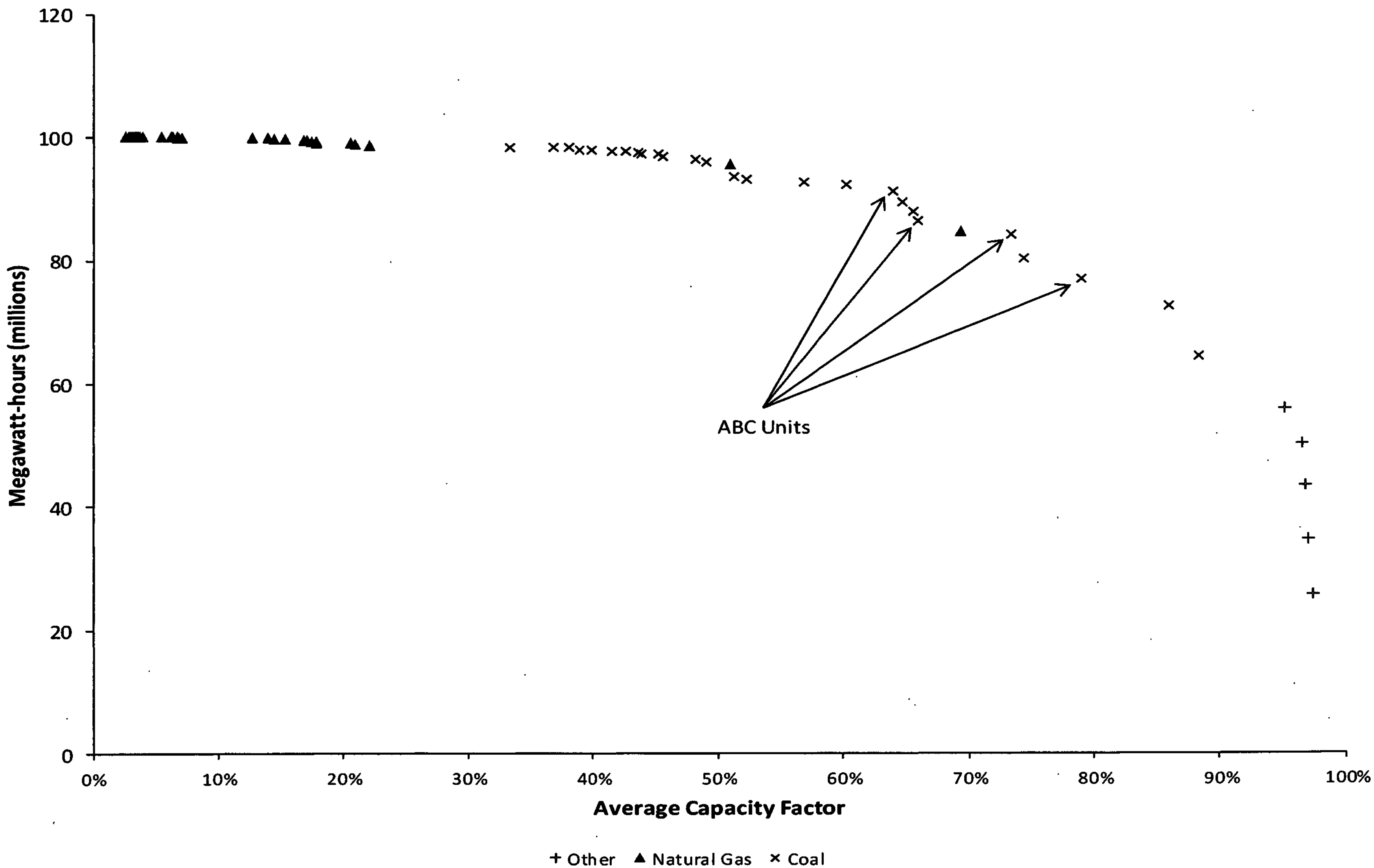

Note: Removed high cost peaking supply for comparability. Supply curve is from September 3, 2012. Total marginal cost of generators modeled by Ventyx as the sum of: fuel cost, variable operations and maintenance cost, total NOx cost, total $SO_2$ cost, total $CO_2$ cost and total mercury cost. Fuel cost sourced from FERC Form 1, EIA-412, RUS-12, EIA-906/923, EIA-423, and Ventyx primary research.

Source: Ventyx

Figure 22A

**CUMULATIVE CONTRIBUTION TO TOTAL PRODUCTION IN ABC PLANT'S REGION BY CAPACITY FACTOR**

July 2010 – June 2011

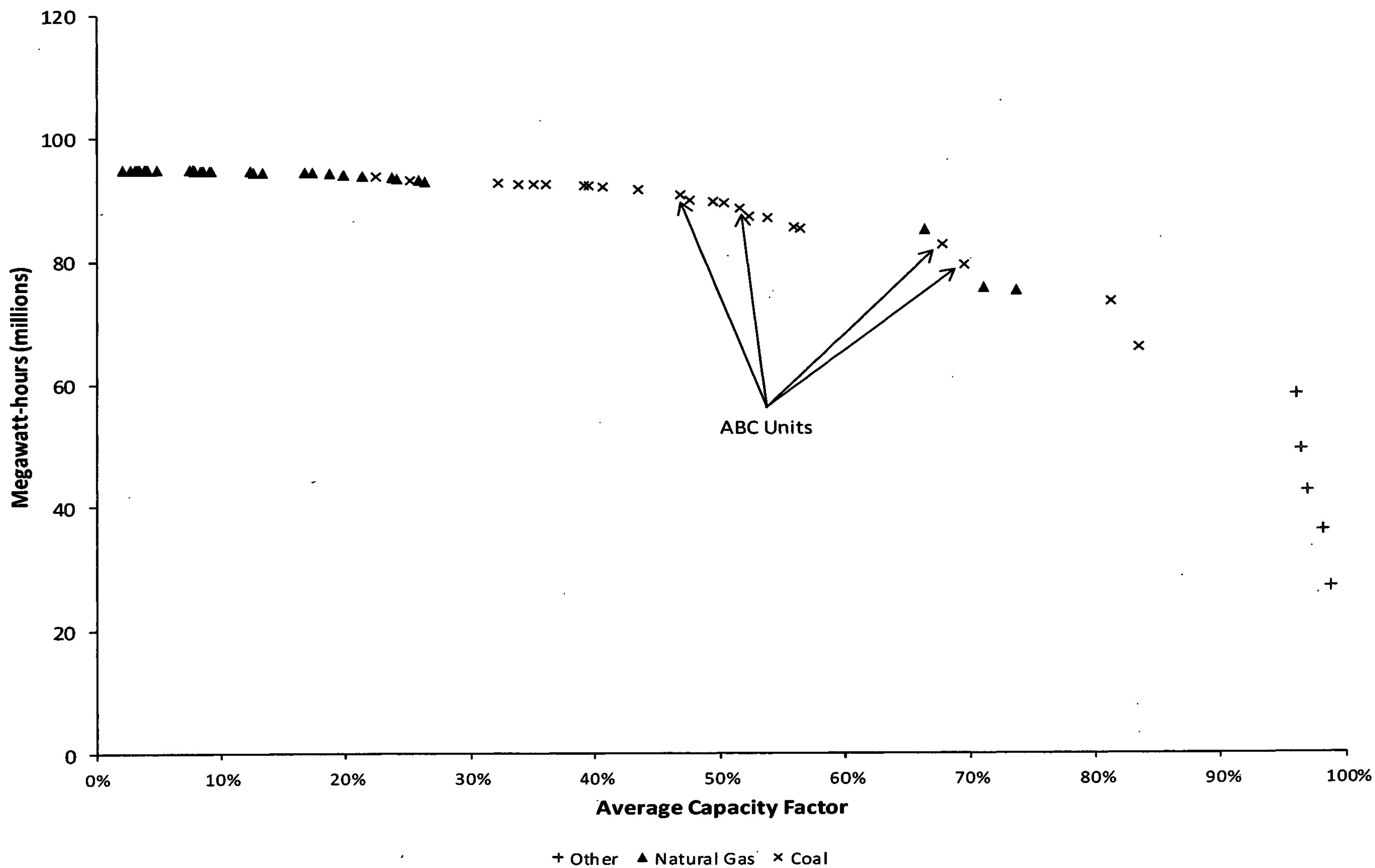



Source: Ventyx, Unit Generation and Emissions – Annual Dataset.

Figure 22B

**CUMULATIVE CONTRIBUTION TO TOTAL PRODUCTION IN ABC PLANT'S REGION BY CAPACITY FACTOR**

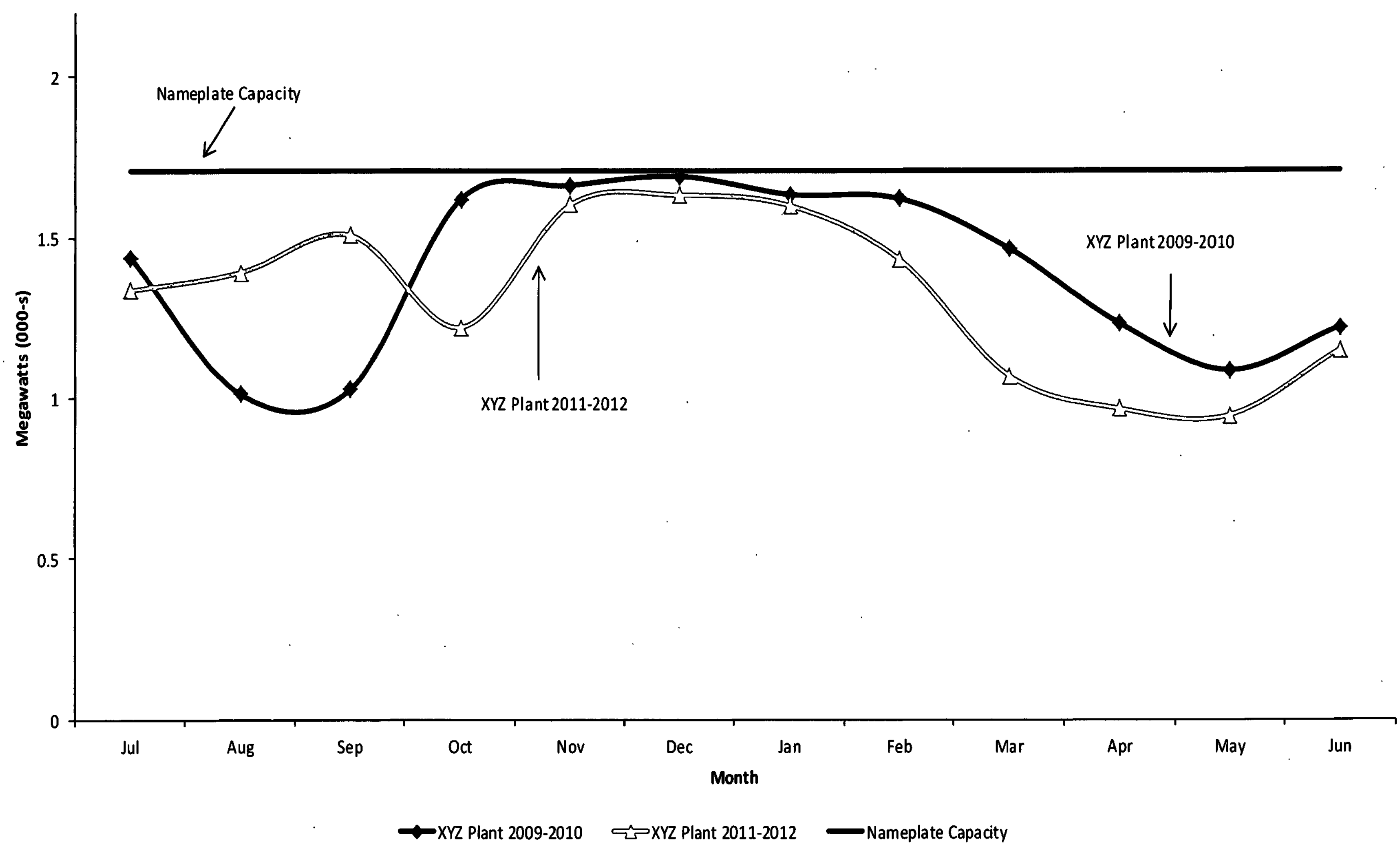
July 2011 – June 2012




Source: Ventyx, Unit Generation and Emissions – Annual Dataset.

Figure 23

## AVERAGE HOURLY PRODUCTION: XYZ PLANT

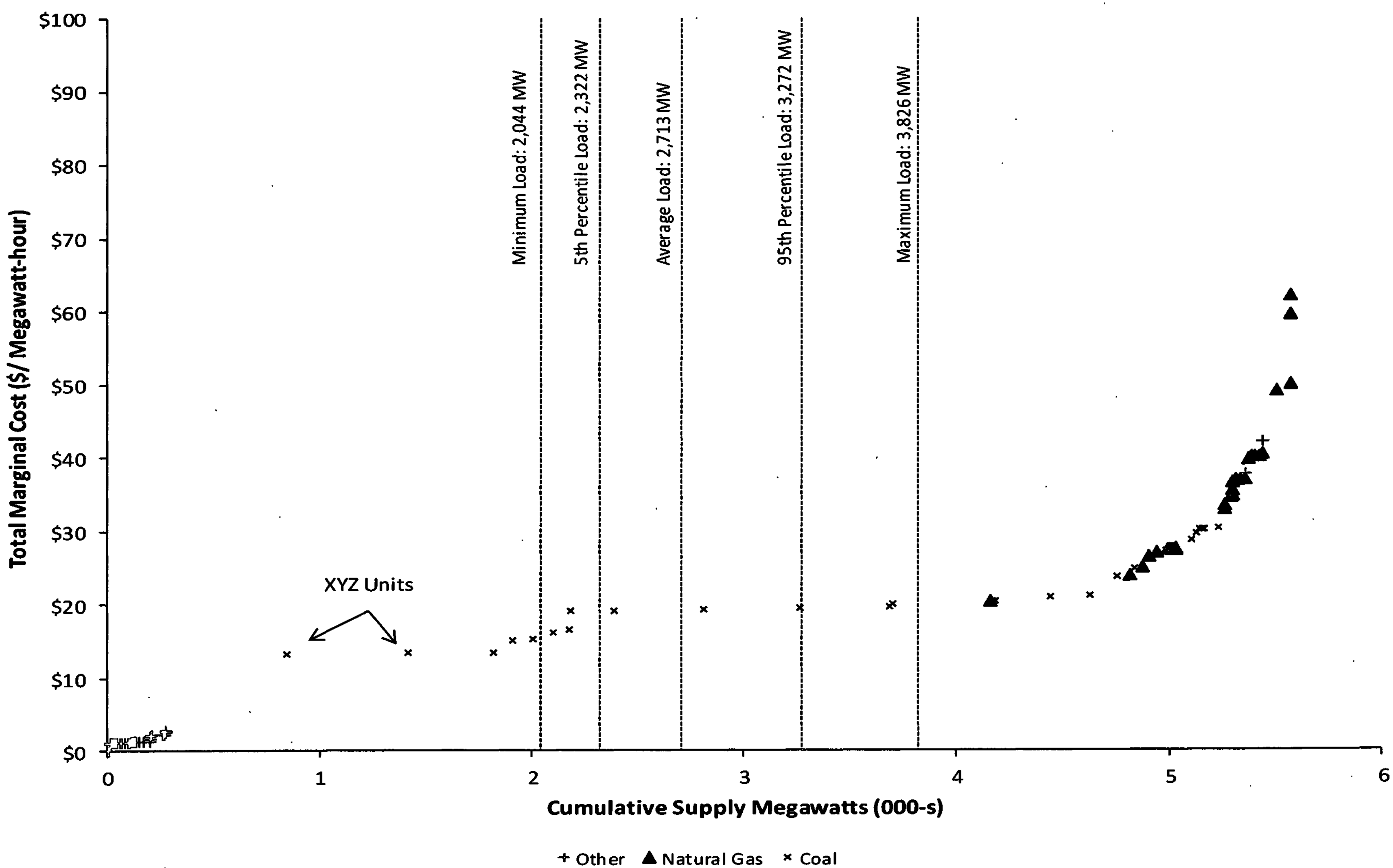



Source: Ventyx, Unit Generation and Emissions Dataset

Figure 24

**ELECTRIC POWER SUPPLY CURVE BY FUEL TYPE**

For XYZ Plant's Region



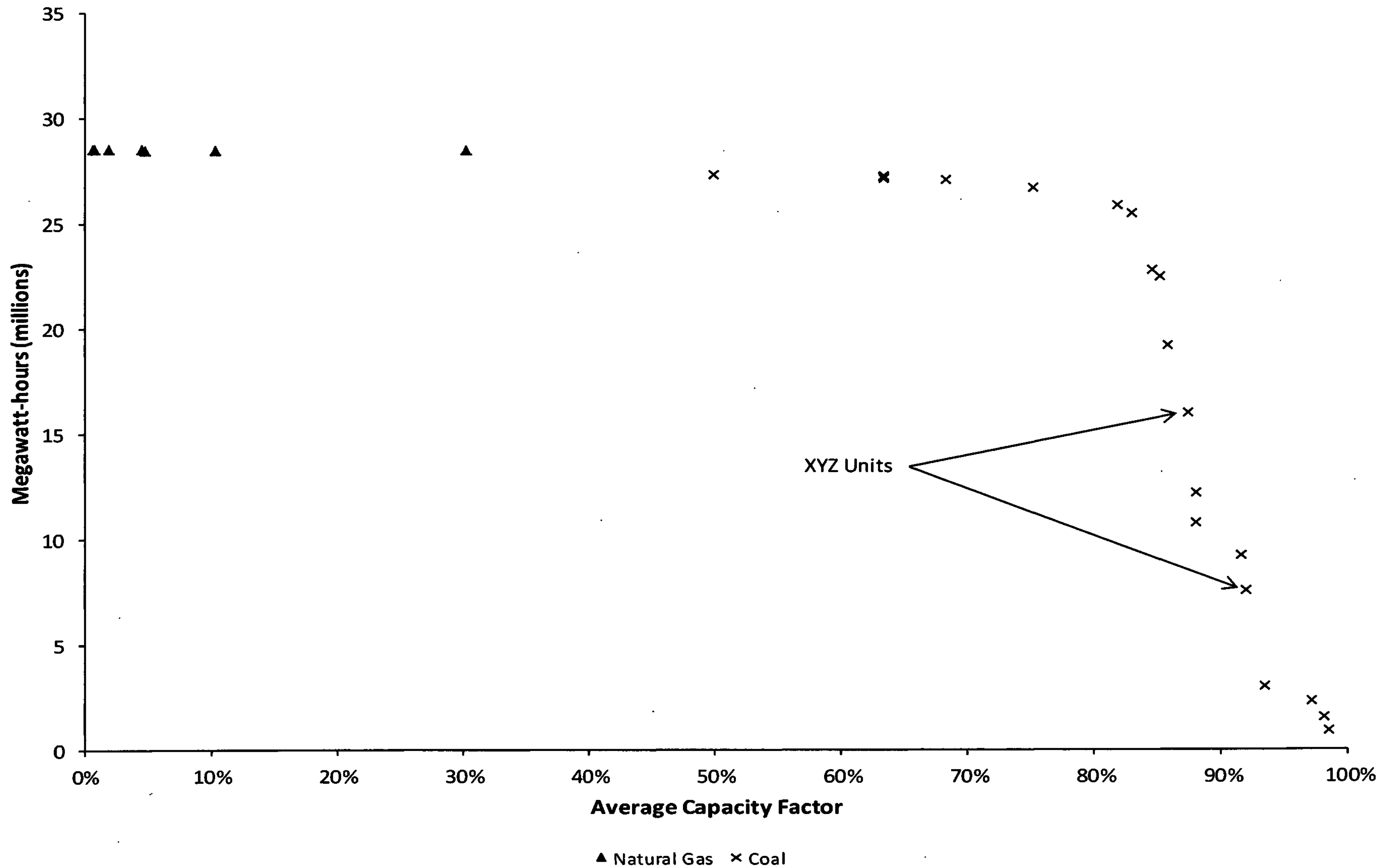

Note: Removed high cost peaking supply for comparability. Supply curve is from September 3, 2012. Total marginal cost of generators modeled by Ventyx as the sum of: fuel cost, variable operations and maintenance cost, total NOx cost, total $SO_2$ cost, total $CO_2$ cost and total mercury cost. Fuel cost sourced from FERC Form 1, EIA-412, RUS-12, EIA-906/923, EIA-423, and Ventyx primary research.

Source: Ventyx

Figure 25A

**CUMULATIVE CONTRIBUTION TO TOTAL PRODUCTION IN XYZ PLANT'S REGION BY CAPACITY FACTOR**

July 2010 – June 2011

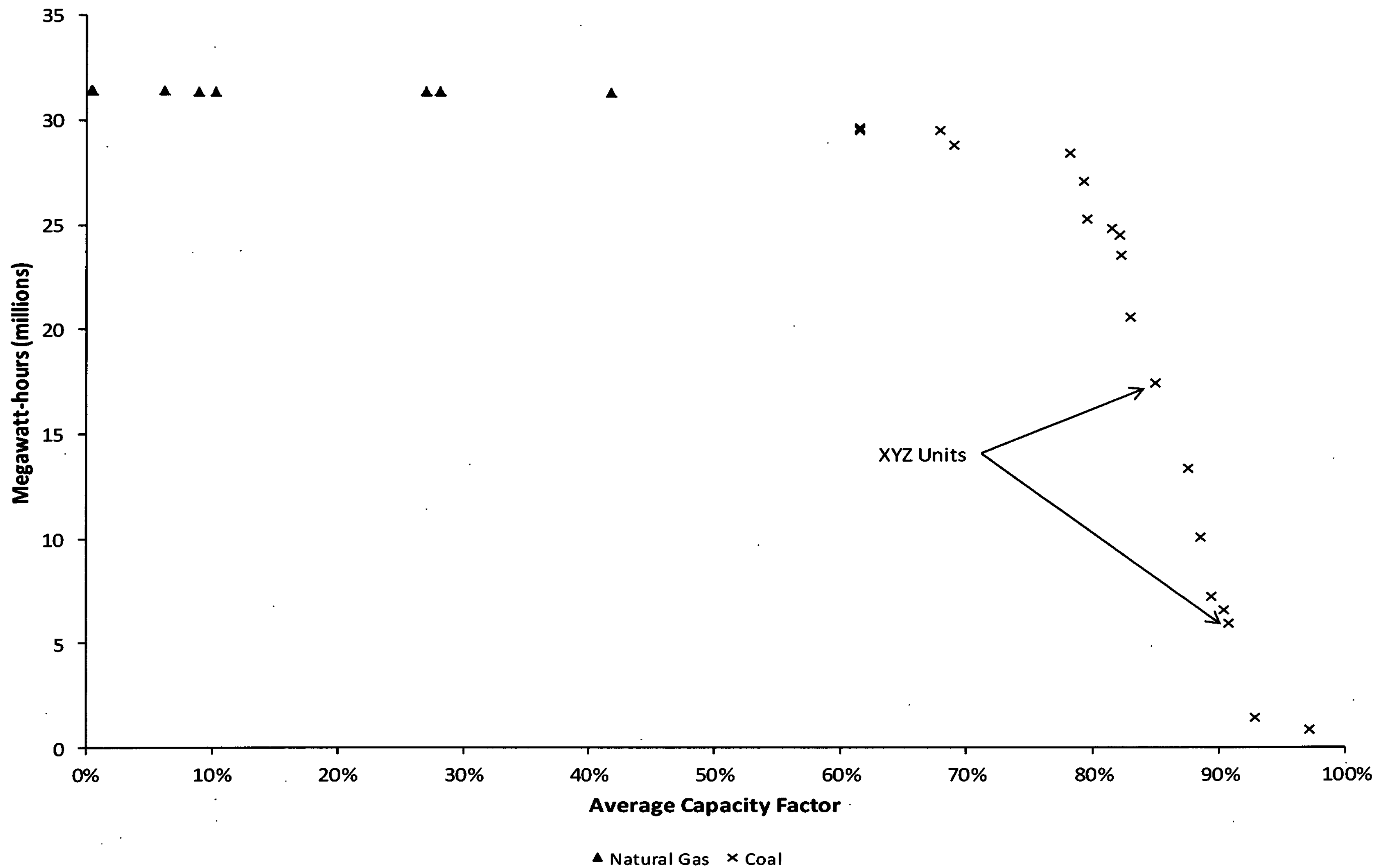



Source: Ventyx, Unit Generation and Emissions – Annual Dataset.

Figure 25B

**CUMULATIVE CONTRIBUTION TO TOTAL PRODUCTION IN XYZ PLANT'S REGION BY CAPACITY FACTOR**

July 2011 – June 2012




Source: Ventyx, Unit Generation and Emissions – Annual Dataset.