Stranded Investment and Non-Utility Generation

by

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I. Introduction

Stranded cost recovery continues to be a focal point of electricity deregulation. Restructuring has ground to a halt in many places largely due to the contentiousness of the issue, and even where there has been action, states have granted substantial stranded cost recovery to utilities vitiating much of the price reductions that competition is forecast to bring.

Proponents of stranded cost recovery make many arguments in favor of this policy polemic. There is the legal contention that stranded costs are a taking if they are not recovered. Next is the plea for fairness: Utilities have operated as servants of the people for these many years and deserve to be honorably treated in regard to their past investments. Finally, there is the factual argument that if stranded costs are not indemnified, future economic prosperity will be jeopardized.

It is this positive-economics argument that we wish to engage. The argument is best characterized in terms of the required rate of return on electric industry capital and is presented most cogently by Baumol and Sidak (1995). The idea is that if prior utility investments are not fully recovered, it will cause the rate of return required by investors in utility assets to increase and thereby increase the price of electricity in the long run.

The proposition has many facets that offer angles of attack. One counter argument is that the rate of return in the electric industry has been inefficiently depressed by regulation and should increase. Competition is one way to achieve this. Kahn has offered a summary judgement of this round of the debate:

[T]o the extent [that] the cost of capital goes up in recognition of the usual risks of the new competitive regime, it reflects a true economic cost and is properly reflect in price. To the extent, however, that it goes up because of regulatory inconsistency and the associated fear that rules changed one way, under altered circumstance, may be changed back, it is neither efficient nor desirable.1

In spite of Kahn’s eloquence and insight, there is more to the story. Stranded cost recovery is fundamentally not about competition or a change in the regulatory regime.

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1 Kahn (1997) p. 35.
Recovery or denial of stranded costs is not a decision that is inextricably tied to regulatory change. Stranded costs do not exist because of competition. Stranded costs exist because of technological progress.

The root cause of the financial effect in the electric industry called stranded costs is the fact that innovations and advances in electric generation technology have caused the true economic cost of generating electricity to decline precipitously. New generation capacity can produce electricity at a full cost—capital and operating—that is approximately equal to the operating cost of existing baseload facilities. This is the cause of stranded costs. If utilities are forced to mark their existing capacity to its true market value based on the replacement cost of these assets, they will have to write off much of the book value.

Of course, this is exactly what competition would force, but the same result could be required in a rate-making regulatory regime. Indeed, it can be argued that if public utility commissions are acting in the public interest, they should force electric utilities to write down the value of their existing assets to reflect the lower replacement cost of these assets, and commissions should do this whether or not they adopt a regime of retail open-access to transmission and distribution facilities.²

This line of argument is based on two empirical premises. The first is that progress in the technology of electric generators is driving stranded costs, and the second is that forcing utilities simply to write off their obsolete equipment will not affect capital investment in the industry. Support for both of these empirical propositions can be found within the electric industry itself.

Right now a substantial portion of electric generation capacity is owned by non-utilities. This segment of the industry is the fastest growing part. Also, this segment of the industry is itself writing off a good deal of obsolete capital. Non-utility generators invested heavily in capital in the 1980s that just like utility generation is now proving to be obsolete. Non-utility generators have no forum from which to argue for stranded cost recovery. Their obsolete equipment is merely written off. In spite of the fact that they are not shielded from the losses imposed by technological progress, this segment of the industry is thriving.

II. The Rise of Non-Utility Generation

In 1973, the Organization of Petroleum Exporting Countries placed an embargo on oil exports to western nations for a period of only six months. Nonetheless, the ramifications and impacts that the embargo had on energy industries throughout the world were dramatic. This was particularly true in the electric power industry where the production of electricity through the use of fossil fuels to run boilers was primarily concentrated in the hands of investor-owned utility companies.³

The energy crisis of 1973 brought to a halt the dramatic and impressive performance that the electric utility industry had achieved in the prior 75 years. The price for fossil fuels increased dramatically. Cost escalation for constructing large generating facilities, particularly

² See Maloney and Sauer (1998). Also, the New Mexico Public Utility Commission recently did both. It gave a Certificate of Convenience and Necessity to an open-access electricity provider and also directed the Public Service Company of NM to write down the value of its generation assets because they are over valued based on the observed wholesale price of electricity. See NMPUC case numbers 2867, 2868, and 2761. However, the New Mexico Supreme Court vacated the NMPUC orders.

³ Investor-owned utilities own around 75 percent of the nation’s total electricity generation.
nuclear power facilities, also rose to alarming rates. These changes reversed decades-old decreases in real electricity prices for consumers. As a result, policy makers began to address strategies to stabilize electricity rates as well as the industry's heavy reliance on imported fossil fuels.

The Public Utilities Regulatory Policies Act of 1978 was one response. The original purpose of PURPA was to create:

(1) a program providing for increased conservation of electric energy, increased efficiency in the use of facilities and resources by electric utilities, and equitable retail rates for electric consumers;

(2) a program to improve the wholesale distribution of electric energy, the reliability of electric service, the procedures concerning consideration of wholesale rates before the Federal Energy Regulatory Commission, and to provide other measures with respect to the regulation of the wholesale sale of electric energy.\(^4\)

A practical implementation of these goals was cogeneration. Encouraging the development of industrial cogeneration met the policy goals of efficiency and reliability in differing ways. Cogeneration results in greater efficiency by using industrial process steam as a heat sink for an on-site industrial electricity generating system.\(^5\) Cogeneration reduces thermal discharge and increases the combined efficiency of the production of electricity and process steam as opposed to producing both of these sources of energy separately.

Greater reliability, another policy goal of PURPA, could also be met by increasing the overall number of generators which could be called upon to meet any given load. Unit (generator) availability was a concern for many energy planners during the mid to late 1970s. During this period, close to 100 nuclear and coal power plant construction projects had been canceled raising questions about how future load projections would be met.\(^6\) In addition, nuclear power plants which were operational, were highly unreliable and suffered from significant unplanned and forced outages during the late 1970s. Cogeneration served the reliability goals of PURPA by expanding the opportunity for a whole new class of generators to meet electricity load. Policy makers reasoned that if a traditional utility generator became unavailable, load could (theoretically) be met by an equivalently sized industrial cogeneration unit.

PURPA was composed of six titles.\(^7\) Title II of PURPA addressed future policy directions for encouraging cogeneration as an energy efficiency and reliability measure. Section 201 of PURPA defined a new type of electric generation entity: a “qualifying

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\(^4\)Public Utilities Regulatory Policies Act, Public Law 95-617, Section 2. This paper will concentrate on the Title II provisions encouraging cogeneration.


\(^7\)Title I: Retail Regulatory Policies for Electric Utilities; Title II: Certain Federal Energy Regulatory Commission and Department of Energy Authorities; Title III: Retail Policies for Natural Gas Utilities; Title IV: Small Hydroelectric Power Projects; Title V: Crude Oil Transportation Systems; Title VI: Miscellaneous Provisions.
facility” (QF). The strict definitions included in Section 201 defined QFs as those which are 
"... owned by a person not primarily engaged in the generation or sale of electric power.”

The key provisions of PURPA (Section 210) are three fold. In large part, these 
provisions were established to address the barriers to cogeneration. The first provision 
requires utilities to interconnect with QFs and to provide standby, emergency, and 
interruptible power. The second provision exempts cogenerators from traditional rate of 
return regulation. The third provision provides a guaranteed market for cogenerated power. 
Under this provision, utilities are required to purchase electricity from a QF at the utilities’ 
avoided cost. This represented a dramatic departure from the typical pricing of electricity 
purchases by utilities which set purchased power rates at the cost of service from the 
supplying source. Under PURPA, purchased power rates would be based on the purchaser’s 
rather than the supplier’s cost.

After the passage of PURPA, FERC began the process of defining the rules under 
which cogeneration would be supported in the electric power industry. Part of the FERC’s 
charge was to define the specific efficiency and ownership restrictions for a QF. In 
addition, FERC also provided the definition of the incremental utility costs upon which 
utility buyback rates for cogenerated power would be based. This definition came to be 
known as avoided costs or the costs avoided by a utility (in terms of capacity and/ or energy 
costs) which were avoided by the utility from a QF purchase. The quantitative 
determination of these avoided costs were left to the states.

The years following FERC’s promulgation of PURPA rules saw a number of 
significant legal challenges that created an aura of uncertainty for industrial firms that sought 
to take advantage of the new provisions of the legislation. These uncertainties were 
removed in the early 1980s by two important Supreme Court decisions: FERC v Mississippi 

In 1982, the Mississippi Public Service Commission brought a action before the U.S. 
Supreme Court regarding the constitutionality of PURPA. The Mississippi PSC specifically 
argued that PURPA mandates to force utilities to purchase cogenerated electricity within 
state jurisdiction violated the Tenth Amendment and was thereby unconstitutional. The 
Supreme Court’s ruling disagreed with the Mississippi PSC’s argument and held that 
PURPA did not trample on states’ rights and was within Congress’ power under the 
Commerce Clause.

In 1983, the Supreme Court went further in supporting PURPA by reversing a lower 
court ruling that FERC’s rules adopting avoided cost pricing for purchased cogenerated electricity were arbitrary and capricious. The Court ruled that FERC had adequately 
explained why avoided costs (as implemented in rule) were just and reasonable to retail 
electricity customers and utilities and in the public interest. This decision, in conjunction 
with the earlier Mississippi decision, removed most legal uncertainties to cogeneration 
development in the U.S.

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8 *Public Utilities Regulatory Policies Act*, Public Law 95-617, Section 2.
9 FERC promulgated rules which defined a QF cogenerator as one which must produce five percent 
of its total energy output as thermal energy. In addition, utility ownership in a cogeneration project must be 
limited to less than 50 percent.
During and after the legal travails following the FERC’s rule promulgation, several states began the process of defining methodologies for avoided cost-based buyback rates. The methods used to determine these rates varied by state. Some of these methods included: \(^\text{11}\)

**Standard Offers**: PURPA requires that state regulatory commissions order utilities to set standing offers to cogenerators. These standard offers set a posted going price for all purchases of electricity. Standard offers were designed to reduce administrative and negotiating costs for cogenerators. Regulators are allowed to set these standard offers for capacity purchases of 100 kW or greater. According to a 1990 survey, about 25 percent of the all states use the legal minimum, 25 percent have no minimum capacity levels for standard offers, while the remaining states use capacity limits ranging between 200 kW to 1 MW. \(^\text{12}\)

**Levelized Rates**: Many state regulatory commissions require that utilities take into account the multi-year aspect of long term buyback contracts with cogenerators by establishing levelized buyback rates. Levelized rates set the long run avoided costs at a constant level over several years. This methodology for setting buyback rates has the effect of increasing cash flow to cogenerators in earlier years and reducing cash flows in later years of the contract period. Such a method assists cogenerators who may face capital and risk constraints in their early start-up years.

**Avoided Cost Methodologies**: The methodologies employed by regulatory commissions in determining avoided costs can have significant impacts on buyback rates for cogenerated power. Many states have varied between requiring utilities to use either short-run or long-run avoided (marginal) costs in order to derive buyback rates for cogenerated power. Short-run marginal costs have the tendency to lower buyback rates since they usually only include the short run operating, maintenance, and fuel costs on marginal units. Long-run marginal costs are typically higher since they could potentially include the capital costs associated with bringing a capacity addition on-line. \(^\text{13}\) Avoided costs methodologies based upon long run marginal costs are typically more favorable for cogenerators.

**Capacity Payments**: Cogenerators have the potential to defer new utility generating capacity. For instance, a cogenerator signing a 30 year contract with a utility may defer a planned utility plant for two years based upon existing load forecasts. If such a situations occurred, some states would allow

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\(^\text{12}\)Ibid.

\(^\text{13}\)This generalization about short and long run marginal costs would be true for a utility experiencing moderate load growth. The higher the load growth, the greater the need for capacity additions, thereby driving up both short and long run marginal costs.
the cogenerator a capacity payment equal to the net present value of the cash savings generated by the cogeneration sales.

**Competitive Bidding**

A more recent innovation in determining avoided costs has been to open future capacity needs for open bids. Here utilities and non-utility generators provide competing bids in an auction to meet future supply needs.

These cost methodologies had a direct impact on the level of the buyback rate for cogenerated power, and as a result, the level of cogeneration which was brought on-line in any given state. Clearly, the more generous the avoided cost methodology, the greater the incentive for cogenerated power. These generous methodologies led to a dual incentive for industrial firms considering cogeneration: (1) an energy efficiency incentive and (2) a profit incentive.14 As a result, a significant amount of cogenerated power came on line during the years following the passage of PURPA. In fact, by 1994, the amount of non-utility generation had more than doubled. The time series is shown in Figure 1.

Implementation of PURPA resulted in a host of new opportunities for cogenerators. Energy efficiency, by lowering overall energy costs, is one significant opportunity for cogenerating firms. Profits, however, represent an additional opportunity for cogenerators, particularly in states where buyback rates through administratively determined standard offer contracts existed. When the profit opportunity exceeds the energy efficiency opportunity, firms have incentives to bring cogenerating units on line which do not comply with the original spirit of PURPA. These cogenerators, often referred to as PURPA machines are typically located in firms which have weak steam needs in their primary production process and are more interested in producing electricity for a profit rather than increasing overall plant efficiencies. Since PURPA requires firms to meet some minimal efficiency standard, profit opportunities give cogenerators incentives to act inefficiently by dumping waste heat (steam) in order to meet the minimum PURPA efficiency standards.15

Utilities also began to gradually realize the potential opportunities of participating as partners in cogeneration projects with industrial firms both within and outside their own service territories. By participating as partners, utilities could negotiate a second-best strategy with industrial firms contemplating leaving the utility system. While utilities could lose a significant amount of load through cogeneration, they could offset these losses by earning a return on their portion of the investment as well as compensation for constructing and/or operating the new cogeneration facility.

Competitive bidding, initially part of the PURPA process in some states, expanded opportunities for cogenerators by providing profit opportunities for meeting utility loads. As these competitive bidding processes were expanded, opportunities for firms whose primary business is in the independent production of electricity also began to arise. These firms represented a new class of electric power generators known as independent power producers (IPPs).

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14A number of studies have examined the incentive structure for firms contemplating cogeneration including: Joskow (1982, 1984); Joskow and Jones (1983), Fox-Penner (1990a, 1990b); Rose and McDonald (1991); and Dismukes and Kleit (1998).

The expansion of electric generating opportunities, first initiated through PURPA-encouraged cogeneration, has changed the definition of non-utility generators or NUGs. In the past, NUGs and cogenerators were typically synonymous since independent power producers (had they existed) would have had no legal market for their power.\textsuperscript{16} However, the expansion of electric generation opportunities has expanded the definition of non-utility generation. Today, 78 percent of all non-utility generation is dominated by QFs and small power producers. There are sizable and growing numbers of electric generators (22 percent of total NUGs) which are not related to PURPA.\textsuperscript{17}

Future projections of the composition of capacity additions in the U.S. show that PURPA related trends will continue into the foreseeable future. In 1994, cogenerators and other NUGs accounted for 8 percent of the U.S. total generating capacity. Between the years 1994-2015, cogenerators and other NUGs are expected to significantly increase their share of the market accounting for 43 percent of all new capacity additions, and 18 percent of all generation capacity.\textsuperscript{18} This dramatic expansion of alternative sources of electricity generation, in concert with a number of other industry changes, has given policy makers an alternative to traditional utility regulation. Namely, using market forces to allocate the most efficient supplies of electricity to their ultimate end uses.

\section*{III. Stranded Non-Utility Generation}

Over the years a significant amount of attention has been given to the extreme examples of generous QF policies and the lucrative cogeneration projects which sprang from these policies. Investment in these non-utility generating facilities, however, does not come without risk. Despite the best made plans, non-utility generating projects can and do fail. When these project fail, NUG shareholders, and not ratepayers, have born the risk of these downturns. Reasons for these failures can include:

\begin{itemize}
  \item failure to complete the appropriate permitting (siting, environmental);
  \item inability to secure financing;
  \item changes in technology;
  \item unanticipated changes in QF contract terms, conditions, and enforcement;
  \item failure to finalize contracts on fuel supply; steam supply, fuel transportation;
  \item difficulty in meeting contract terms with purchasing utility.\textsuperscript{19}
\end{itemize}

Gathering information on failed or shutdown non-utility generators is difficult. NUGs are typically not subjected to the same type of reporting as their public utility counterparts. Even when NUGs are required to provide information, it is typically

\textsuperscript{16}Franchise agreements would have precluded IPPs from serving an retail customer independently. In addition, prior to PURPA few (if any) competitive bidding processes for new utility capacity needs existed.

\textsuperscript{17}U.S. Department of Energy. \textit{Annual Energy Outlook} 1996 29.

\textsuperscript{18}Ibid

considered confidential. Thus, gathering even simple information on project capacity, prime mover, commercial operation date, location, project shutdown date and reason can be troublesome.

There are two types of information on NUG that indicate the extent of obsolescence in this sector of the electric industry: case-by-case examples and broad industry survey information. Case-by-case information provide spotty but revealing information about past NUG failures. Broad industry survey information unveils general trends, but no specific information on the underlying causes of NUG failures. In the following two sections we survey both sources of information on recent NUG failures in an attempt to draw some conclusions regarding the causes and consequences of NUG failures.

### III a. Case studies of reported NUG failures

A number of NUG projects have failed in recent years despite completing initial project contracts with purchasing utilities. Some recently reported NUG failures have been attributed to: regulatory disapproval; failure to complete contract milestones on contacted dates; and changes in project characteristics which differ from earlier contractual agreements.

**Case 1: Regulatory Disapproval:** In 1992, the Massachusetts Department of Public Utilities (DPU) denied approval to wood-fired QF which had entered into a contract with the purchasing utility through an RFP process. The DPU rejected the final approval of the project because it had differed too much from that contracted under the RFP: project ownership had changed; project technology was changed from a wood-gasification to wood stoker; capital structure of the project was changed; and the size of the facility was reduced.

**Case 2: Failure to Meet Project Milestones:** In mid-1997 three IPPs were forced into bankruptcy when they failed to meet the exact commercial operation dates specified in their contract with Florida Power & Light Company.

**Case 3: Changes in Project Representation:** A 250 MW, $470 million coal-fired power project sponsored by AES was canceled at 50 percent completion due to the failure to follow-through on the proposed shut down of three boilers. Maintaining the boilers was in stark contrast to the original terms and conditions of the project. Investors reportedly sued AES for misleading both investors and regulators. U.S. Generating Company subsequently took over management of the project and was able to successfully have regulators reinstate the project environmental and construction permits.

Other examples of canceled and beleaguered NUG projects have been provided in Table 1.

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20 DOE Form 867 and Form 900 require non-utility generators greater than 1 MW to file general per plant statistics on a monthly (Form 867) and annual (Form 900) basis. However, this information is considered confidential on a plant-level basis and is not released to the public.

21 Examples cited in this section were originally reported in Ferry, *Law of Independent Power*, Section 3.07[3].
III b. Summary Evidence on NUG failures

Our empirical examination draws from two data sources on non-utility generation: the Edison Electric Institute (EEI) and the Utility Data Institute (UDI). The EEI information we examined is an annual aggregation of non-utility generation closure statistics. The information we gathered is from a special search of the database used to publish EEI's annual report *Capacity and Generation of Non-Utility Sources of Energy*. Due to proprietary concerns, EEI does not publish non-utility, plant-specific information. The data is tabulated from annual surveys of utilities about non-utility source of generation in their respective service territories.\(^{22}\) Data limitations, due to proprietary concerns, only allow us to examine general trends from EEI sources and not plant-specific closures. The data available to us are the capacity of non-utility generation in each state that is out of service classified by the year of initial commercial operation.

Another source of information, one which does provide plant-specific information is the *Directory of U.S. Cogeneration, Small Power and Industrial Power Plants* published by the Utility Data Institute. This survey-based information is collected by UDI from a variety of sources including: electric power trade press; utility publications and sources; state regulatory commission reports; FERC filings; and other sources. UDI indicates that much of the information is verified through some follow-up surveying. The UDI database includes over 4,900 cogeneration, small power, and independent power plants including plants which are currently operational, under construction, planned, deferred, and most importantly, those which are shutdown. The UDI data does not identify the year in which NUG facilities were shutdown, but does allow for an examination of shutdown NUG facilities by the year of initial commercial operation.

In order to get the best picture of NUG shutdowns, we combine the information from the two data sources in the following fashion. For each year of initial commercial operation and for each state, we count the shutdown capacity as the maximum reported by EEI and UDI. Because operating units are only reported by UDI, if the shutdown capacity reported by EEI in a given state and for a given year is greater than that reported by UDI, we subtract this from the operating capacity down to the floor of zero.\(^{23}\)

Table 2 presents summary data on plant closures taken from the two datasets through 1994. The center column in Table 2 presents the combined shutdowns reported by EEI and UDI by each year of initial operation. The right-hand column reports operating NUG capacity from UDI netted by EEI reported shutdowns. The data are broken into pre- and post-PURPA time periods. For many plants the date of commercial operation is not known or is only known relative to the PURPA watermark. The data indicate that a total of 4978 MWs of non-utility generation had been taken out of service compared to 55,495 MW that were still reported as operating in 1994.

Table 3 shows the data in percentage terms. At the end of the period covered by these data, shutdown capacity across all reported units was 8.2 percent of total reported installations. That is, to get this percentage we added the total shutdowns across all

\(^{22}\) In their 1995 report, EEI surveyed 141 investor-owned electric operating companies and 145 publicly-owned utilities. A total of 138 IOUs and 134 municipals reported NUGs in their service territories representing 73 percent of all IOUs and 56 percent for all municipals for a total response rate of 63 percent. Edison Electric Institute, *1995 Capacity and Generation of Non-Utility Sources of Energy*. Washington: Edison Electric Institute: 77.

\(^{23}\) Our own limited survey of NUG capacity indicates that UDI under reports units as shutdown.
commercial operation dates, which is 4978 MW reported in Table 2, to the total operating
capacity, 55,495 MW, and then took the ratio of shutdowns to total installations. The
middle column of Table 3 shows the percentage of capacity installed in each year that has
been shutdown. In percentage terms, 1980 had the most relative shutdowns, while 1986, the
year with the largest amount of capacity that has been shutdown, the relative amount of
capital retired is 15.3 percent. The last column of Table 3 shows the distribution of the
capacity installed after PURPA that has been shutdown.

While the information that we have on NUG shutdowns is limited, three general
trends are discernible.

**Trend 1: A substantial amount of non-utility generation has been shutdown or stranded**

The non-utility generating sector is not exempt from risk. As noted earlier,
problems can arise in terms of changes in the economy, changes in technology, changes in
regulation, contracting difficulties, among others, which change economic NUG projects
into uneconomic ones.

Of the non-utility generation that came on line between 1978 and 1994, a significant
percentage has been retired or mothballed. Based on the two surveys of non-utility
generation, there was 50,666 MW of non-utility generation installed over this period. Of
this, Table 3 shows that over 5.5 percent is shut down. Even more striking is the fact that
nearly 10 percent of the investment made in the 1980s has been retired, and 17 percent of
the investment in the first half of the 1980s is out of service. It is not surprising that more
of the older units in this vintage have been retired. However, the magnitudes of these
shutdowns are substantial.

**Trend 2: Most shutdown non-utility generators were qualifying facilities**

Qualifying facilities, initiated by PURPA, have represented the overwhelming
number of both NUG capacity additions and shutdowns. Figure 2 shows the distribution.
In the post-PURPA era, QF shutdowns represented approximately 64 percent of all NUG
shutdowns. Small power producers (SPPs), which are small renewable source of generation
created under PURPA, represents the second highest proportion of NUG cancellations at
26 percent of total cancellations. Exempt wholesale generators (EWGs) created by the
Energy Policy Act and self generating facilities (those facilities which self-produce power
and do not sell back into the integrated power grid, represent small portions of NUG
shutdowns.

**Trend 3: Despite NUG shutdowns, a significant amount of NUG capacity has continued to come
on line**

Even though NUG cancellations have been substantial for facilities which reached
commercial operation during the first half of the 1980s, capacity has been forthcoming.
While we do not know exactly when the plants that went into operation in the early to mid-
1980s were shutdown, there has been unwavering increases in NUG capacity through the
end of the reporting period. As can be seen in Table 2, over 10 percent of the capacity on-
line in 1994 was installed in that same year and over 40 percent was installed in the 1990s.

Figure 3 shows this graphically by depicting the distribution of non-utility generation
cancellations by year of initial commercial operation alongside non-utility generation
capacity additions as a percent of total U.S. generating capacity additions. The left scale and
the square labels show the percentage of non-utility generation installed in each year that
has since been canceled. The right scale and the triangles show the percent of total
generation capacity additions for the industry that are comprised by non-utility generators.

As shown in Figure 3, non-utility generation is making up a larger and larger
percentage of total capacity additions. Non-utility generation made up half of the total
capacity additions in the electric industry in the first half of the 1990s. This has grown from
10 percent in 1982 and less than 20 percent in 1986. Figure 3 also shows the wave of
cancellations that has occurred among plants installed in the 1980s.

Figure 3 highlights the dramatic nature of the non-utility generation market.
Investors looking back at the obsolescence rate of capacity installed in the past must worry
that this wave will soon crash down on current capacity additions. Nonetheless, capacity
continues to be put in place. The amount of non-utility generation capacity that has been
installed over that last several years is impressive on its own, it is impressive relative to the
amount of utility generation that is being installed, and it is impressive relative to the
amount of prior capacity that is being written off by the forces of competition acting on the
non-utility generation sector of the industry.

IV. Conclusions

When we examine the historical experience of the non-utility segment of the electric
industry we are left with two inescapable conclusions: 1) Obsolescence is a pervasive
phenomenon in the electric industry; and 2) capital markets for electric generation assets do
not dry up when obsolete assets must be written off.

Technological progress has pushed many generation assets over the line. Assets
whose operating costs are in excess of the market price of electricity are uneconomical. In
the non-utility sector of the electric industry these uneconomical assets are generally forced
to shut down as well they should throughout the entire industry. The competitive wholesale
market for electricity is but a benchmark on this process. The true opportunity cost of
electricity is based on the full cost, that is, capital and operating costs of new generation
capacity. Existing assets for which operating costs exceed this value are uneconomical and
should be retired.\footnote{We are speaking here of baseload units. The same analysis applies to peaking units, and it is
possible to retain some units, not economical for baseload applications, for service in peaking situations.}

We have showed that there is a substantial portion of the non-utility generation
capacity that has been shutdown. This shutdown capacity comes from the older part of the
NUG capital stock, but still it is capital is relatively young compared to historical physical
depreciation rates in the electric industry. The pace of technological progress in the electric
industry is picking up speed. It is changing the face of this industry like many others in the
last decades of the 20th century.

What is equally clear from the evidence is that the financial impact of obsolescence
in the non-utility sector of the electric industry has not choked off capital investment. It is
apparent that in the competitive segment of this industry like others, entrepreneurs are
willing to accept the risk of technological obsolescence. Time and again we see firms
investing large sums in products and technology with the almost certain expectation that
these devices will become obsolete before they wear out. Technological progress threatens
the value of capital assets in all lines of business. Technological progress lowers the cash

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flows that can be derived from the operation of existing capital, thus making it obsolete. Financial markets take this into account when the capital is first put into place. When the expectation of obsolescence becomes eventuality, the market moves on.

We think that the implications of these observations for restructuring policy are profound. Economic efficiency is deeply tied to technological progress and the market economy is capable of absorbing the negative side effects of technological change. In this sense, stranded cost recovery is neither warranted based on the public interest model of regulation nor necessary when assessing the long-run prosperity of the industry and economy.

References


Non-Utility Generation


Table 1: NUG Project Failures 1987-1992

<table>
<thead>
<tr>
<th>Leading Sponsor</th>
<th>Cancel Date</th>
<th>Type</th>
<th>Size (MW)</th>
<th>Cost ($M)</th>
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<td>Coal</td>
<td>2000</td>
<td>90</td>
<td>Failed power sales contract</td>
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<td>Milesburg Power, Subsidiary of</td>
<td>1990</td>
<td>Waste</td>
<td>30</td>
<td></td>
<td>Failure to reissue tax-exempt bonds</td>
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<td>1989</td>
<td>Wood/gas</td>
<td>80</td>
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<td>Wood/gas</td>
<td>80</td>
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<td>20</td>
<td>Financial difficulty, unanticipated fuel price escalation</td>
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<td>23</td>
<td>Financial difficulty</td>
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<td>Wood/waste</td>
<td>24</td>
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<td>Babcock &amp; Wilcox, (Norse Energy)</td>
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<td>Failure to meet contract milestone</td>
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<td>25</td>
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<td>Kaiser-Permanent</td>
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<td>Decker Energy</td>
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<td>Wood</td>
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<td>1988</td>
<td>Coal</td>
<td>15</td>
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<td>1988</td>
<td>Gas</td>
<td>142.5</td>
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<td>28</td>
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<td>Bio-Mass Power</td>
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<td>Biomass</td>
<td>7.5</td>
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<td>Dravo Corp.</td>
<td>1988</td>
<td>Waste</td>
<td>78</td>
<td></td>
<td>Regulatory delays</td>
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<td>ASK Technology</td>
<td>1990</td>
<td>Waste</td>
<td>20</td>
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<td>General Electric Credit Corp</td>
<td>1990</td>
<td>Waste</td>
<td>20</td>
<td></td>
<td>Emissions problems</td>
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<td>Archibald Power Corp.; Subsidiary of FPL</td>
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</table>

Ibid, 3-66.0 - 3-66.8.
# Non-Utility Generation

## Table 2: Comparison of Shutdown to Operating Non-Utility Generation

<table>
<thead>
<tr>
<th>Commercial Operation Date</th>
<th>Shutdown Capacity (MW)</th>
<th>Operating Capacity (MW)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Pre PURPA*</td>
<td>1902</td>
<td>4197</td>
</tr>
<tr>
<td>Unknown*</td>
<td>279</td>
<td>3429</td>
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<tr>
<td>Post PURPA*</td>
<td>13</td>
<td>0</td>
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<tr>
<td>1978</td>
<td>0</td>
<td>265</td>
</tr>
<tr>
<td>1979</td>
<td>0</td>
<td>410</td>
</tr>
<tr>
<td>1980</td>
<td>226</td>
<td>447</td>
</tr>
<tr>
<td>1981</td>
<td>43</td>
<td>193</td>
</tr>
<tr>
<td>1982</td>
<td>167</td>
<td>1231</td>
</tr>
<tr>
<td>1983</td>
<td>348</td>
<td>953</td>
</tr>
<tr>
<td>1984</td>
<td>329</td>
<td>2666</td>
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<tr>
<td>1985</td>
<td>285</td>
<td>3327</td>
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<tr>
<td>1986</td>
<td>464</td>
<td>2568</td>
</tr>
<tr>
<td>1987</td>
<td>174</td>
<td>4013</td>
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<td>1988</td>
<td>200</td>
<td>4021</td>
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<td>1989</td>
<td>218</td>
<td>3865</td>
</tr>
<tr>
<td>1990</td>
<td>202</td>
<td>5511</td>
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<td>1991</td>
<td>40</td>
<td>4715</td>
</tr>
<tr>
<td>1992</td>
<td>33</td>
<td>4749</td>
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<tr>
<td>1993</td>
<td>52</td>
<td>3138</td>
</tr>
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<td>1994</td>
<td>2</td>
<td>5798</td>
</tr>
<tr>
<td><strong>Total</strong></td>
<td><strong>4978</strong></td>
<td><strong>55,495</strong></td>
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</tbody>
</table>

* Exact Commercial Operation Date unknown.  
Notes: Data are the combination of surveys of EEI and UDI. Data are incomplete past 1994. Capacity is generation installed in each year. Date that capacity was taken out of service is not known.
## Table 3: Percentage Distribution of Shutdown NUG Capacity

<table>
<thead>
<tr>
<th>Year</th>
<th>Percentage of Capacity Installed in each Year that has been Shutdown</th>
<th>Percent of Post-PURPA Shutdowns Occurring in each Year</th>
</tr>
</thead>
<tbody>
<tr>
<td>1978</td>
<td>0.0%</td>
<td>0.0%</td>
</tr>
<tr>
<td>1979</td>
<td>0.1%</td>
<td>0.0%</td>
</tr>
<tr>
<td>1980</td>
<td>33.5%</td>
<td>8.1%</td>
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<tr>
<td>1981</td>
<td>18.4%</td>
<td>1.6%</td>
</tr>
<tr>
<td>1982</td>
<td>11.9%</td>
<td>6.0%</td>
</tr>
<tr>
<td>1983</td>
<td>26.8%</td>
<td>12.5%</td>
</tr>
<tr>
<td>1984</td>
<td>11.0%</td>
<td>11.8%</td>
</tr>
<tr>
<td>1985</td>
<td>7.9%</td>
<td>10.2%</td>
</tr>
<tr>
<td>1986</td>
<td>15.3%</td>
<td>16.7%</td>
</tr>
<tr>
<td>1987</td>
<td>4.2%</td>
<td>6.3%</td>
</tr>
<tr>
<td>1988</td>
<td>4.7%</td>
<td>7.2%</td>
</tr>
<tr>
<td>1989</td>
<td>5.3%</td>
<td>7.8%</td>
</tr>
<tr>
<td>1990</td>
<td>3.5%</td>
<td>7.2%</td>
</tr>
<tr>
<td>1991</td>
<td>0.8%</td>
<td>1.4%</td>
</tr>
<tr>
<td>1992</td>
<td>0.7%</td>
<td>1.2%</td>
</tr>
<tr>
<td>1993</td>
<td>1.6%</td>
<td>1.9%</td>
</tr>
<tr>
<td>1994</td>
<td>0.0%</td>
<td>0.1%</td>
</tr>
</tbody>
</table>

- Percent of all Recorded NUG Capacity that has been Shutdown: 8.2%
- Percent of all Post-PURPA NUG Capacity that has been Shutdown: 5.5%
- Percent of the NUG Capacity installed in the 1980s that has been Shutdown: 9.5%
- Percent of NUG Capacity installed from 1980-1984 that has been Shutdown: 16.9%
Figure 1: Non-Utility Generation Capacity as a Percent of Total US Generating Capacity

Figure 2: Canceled NUGs in Post-PURPA Period by Type of Facility

Figure 3: Shutdowns and Additions of Non-Utility Generation