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The Direct Costs and Benefits of US Electric Utility Divestitures

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Abstract

This paper studies the impact of divestiture on the efficiency and costs of electric utilities. The empirical literature shows that there exist economies of scope for electric utilities and that divestiture decreases distribution efficiency but increases generation efficiency. This paper is to bring together these different results. Our analysis covers distribution, transmission, and power sourcing. Our data is an unbalanced panel of about 138 US electric utilities for the years 1994 to 2006 over which we observe 30 divestitures between 1997 and 2003. First, we regress firm-level efficiencies for distribution and power sourcing on various divestiture indicators. Second, we compare the weighted cost between divested and non-divested firms and calculate a net present value for the entire sample of divestitures. Last, we regress net benefits from divestiture on the distribution side on the net benefit for power sourcing to see whether individual firms successfully off-set any costs of divestiture. We find that divestiture reduces distribution efficiency but increases power sourcing efficiency. Both effects depend on the amount of own nuclear generation output but not fossil-fuel or hydro output. The net present value for all divestitures in our sample is \$11.3 billion. It seems that relatively lower costs of power outweigh losses in economies of scope as well as other restructuring costs. However, lower costs of power might be the result of favourable contracts put in place at the time of divestiture. Our study complements traditional studies of economies of scope and shows that divestitures might well be worth it.





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1 Introduction

Many economists⁴ and regulators believe that both the vertical unbundling of generation and distribution is essential for competition in electricity markets and that at least in a static setting there is a trade-off between a loss of vertical economies of scope and benefits from enhanced competition. But the empirical literature on the effect of vertical divestiture focuses on economies of scope alone. See for instance Kaserman and Mayo (1991) and Kwoka (2002) which find substantial economies of vertical integration for electric utilities. Studies that look at the effect of divestitures on efficiency find that divestitures and restructuring typically reduce distribution efficiency (Kwoka et al., 2010) but increase generation efficiency (Fabrizio et al., 2007). To the best of our knowledge this is the first study that at least for the electricity

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industry looks at the overall effect of divestiture including distribution, generation, and transmission, explicitly quantifying its impact. We take into account economies of scope, inefficiency, and cost of sourcing power.

A technology that is characterized by economies of scope does not necessarily imply that actual divestitures are detrimental because a retreat by the frontier might be outweighed by an increase in efficiency and lower margins. Taken together the empirical literature suggests that decreases in generation costs and prices might outweigh losses in economies of scope as well as other restructuring costs. It is possible that technological and organizational innovations compensate for or reduce initial losses in economies of scope over time. Kwoka (2002) for instance shows that holding structures can compensate for vertical integration.

This paper studies the impact of a sample of 30 US generation asset divestitures which took place between 1994 and 2006 on firm performance. First, extending the analysis of Kwoka et al. (2010) we ask what is the impact of divestiture on distribution efficiency and on the relative unit cost of sourcing power? Our second question is: what is the net present value (NPV) for this sample of divestitures? Third, we ask whether the net benefits on the distribution and power sides are related at the firm level? The first question is addressed by regressing firm-level efficiencies on a set of divestiture indicators. The second question is answered by comparing the weighted costs between divested and non-divested firms where the weights are efficiency measures. Thus the efficiency measures are both directly analyzed and used as an input into the quantification of the net benefit of divestiture. For the third question we regress firm-level net benefit measures for distribution and power sourcing.

The results show that divestitures reduce distribution efficiency but that the gap with non-divesting firms shrinks over time. Divestitures also decrease the unit cost of power, though costs for divesting companies are higher to start with. When quantifying net benefits we find that divestitures incur costs on the distribution side that are outweighed by benefits on the power side. The NPV for our sample is \$11.3 billion. We also find that the net benefits for distribution and power sourcing are positively correlated especially for divestitures that incur relatively high costs.

This paper is divided into nine sections. Section 2 provides some background for the divestitures we study. Section 3 briefly reviews the relevant empirical literature. Section 4 states our hypotheses. Section 5 outlines our analytical approach. Section 6 summarizes the data and gives details on our variables. Section 7 gives the results. Section 8 discusses the results and section 9 concludes.

2 Background

This section discusses US restructuring focusing on the circumstances of divestitures that are relevant for the interpretation of our results. For a general overview of restructuring see Delmas and Tokat (2005) or Kwoka et al. (2010). After changes in federal energy laws and regulation many states embarked on a path towards electricity restructuring in the second half of the 1990s with the long-term objective of allowing competition in wholesale and retail markets for electricity. Restructuring was partly motivated by increasing rates in restructuring states during the 1980s. According to

Basheda et al. (2007) restructuring has been successful in the sense that it brought rates in line with fuel costs. Whereas some restructuring states forced (or nudged) companies to divest others did not. Maschoff et al. (1999) and Rowe et al. (2001) detail the strategic considerations of both the sellers and buyers of generation capacity. Voluntarily sales - Kwoka et al. (2010) show that most divestitures are voluntary - are driven by the following consideration: vertical differentiation (e.g. GPU Inc., Montana Power, ComEd), high sales price combined with the need for funds to diversify into non-utility businesses (ComEd/Unicom)⁵, and stranded cost recovery (California) as discussed by Michaels (2006).

As Kwoka (2002, Table 1) observes that purchasing power is more expensive than generating power (including capital charges) it is likely that many sales are driven by strategic considerations. Additionally, the flow-through character of purchased power expenses in traditional regulation produces a bias towards own generation. Many regulators that introduce performance based regulation (PBR) or retail customer choice abolish automatic adjustment clauses bringing in line the incentives for cost reduction for own generation and purchased power (Biewald et al. 1997, p. 33). But, the relative costs and benefits of own generation are likely to change with the rise of competitive wholesale markets.

In the short run, regulators in restructuring states had two objectives: to turn incumbent generation units into viable stand-alone generation companies and lower tariffs for customers. Often these objectives had the perverse effect of hindering independent entry into generation and thereby endangering competition in the longer run. In order to achieve these short-run goals regulators typically took the following measures: reallocate costs from generation to distribution, unbundle costs on customer bills, introduce a transition charge to cover stranded costs, cap or reduce regulated retail tariffs, and sanction long-term buy back contracts between distribution companies and their former generation units. Whereas in some states the reallocation of costs from generation to distribution was sanctioned (and often welcomed) by the regulator (Maloney et al., 1997) in others costs were reallocated without the regulators consent and possibly the intention of gaining an unfair competitive advantage in generation. Also, most regulators were anxious to produce immediate benefits for customers in the form of lower tariffs. Newly regulated standard tariffs often implied fixed percentage reductions compared to the tariffs before restructuring and were often frozen for the transition period. Such regulated standard offers often turned out to be priced below competitive rates because these were higher than expected (Pfeifenberger et al., 2004, endnote 3). In order not to suffer a squeeze like the Californian utilities many distribution companies that divested their generation assets and faced capped retail tariffs entered into buy-back contracts with their former generation units, whether owned by holding companies or not (Pfeifenberger et al., 2004). And contract

⁵ Janet Gail Besser, Chairwoman, Mass. DTE comments on the sale of plants in Schuler (1998): "It is a great development. We are getting premiums for our power plants. One and one-half over book [value] for Mass Electric, something like one and one-half to two over book for Boston Edison, and six times over book for Com Electric. Com Electric is one of our highest priced utilities here in Massachusetts. Clearly the subsidiary of The Southern Co. that bought the power plants there wants to be in this market, wants to get a foothold. Selling your plants early is a real advantage. Six times over book. In a regulatory setting we could have never gotten that. We would have probably been thrown out of court on one and a half times over book."

prices were often linked to regulated standard offers. But in some states (e.g. California) buy-back contracts do not exist because all electricity has to be sold through central clearing mechanisms (including the power firms generate themselves). In total only nine states started such competitive procurement of regulated generation services before the end of our sample (Pfeifenberger et al., 2004, Table 2), i.e. by 2006.

Given this discussion three issues are important for the analysis below. First, since costs were re-allocated at divestiture analyzing distribution or generation alone is likely to over or underestimate the effect of divestiture. Second, due to regulatory restrictions on firm behaviour during transition periods we might not observe the true impact as in many cases our sample does not extend beyond the transition period. In particular, the cost of purchased power might be artificially low for divested companies, inflating the benefits of divestiture. Last, divestitures often coincided with other regulatory changes like the introduction of performance based regulation (PBR) or retail competition making it difficult to attribute effects to divestiture only. See Olson and Richards (2003), Biewald et al. (1997), and Sappington et al. (2001) for an overview of PBR regulation. Like all regulation in the US PBR plans are highly firm specific. A plan might target specific indicators like fuel efficiency or be as broad as a general price cap. Also, it might treat generation and transmission and distribution (T&D) costs symmetrically or not. Such variety makes it even more difficult to disentangle the various effects.

3 Literature

Production theory suggests that vertical unbundling leads to cost increases when the technology exhibits vertical economies of scope as a result of indivisible inputs or cost complementarity between outputs. The two most recent studies that estimate economies of scope for US electric utilities conclude that there exist economies of scope for electricity generation and distribution.

Kwoka (2002) finds strong evidence for cost complementarity and mixed evidence for indivisible inputs for generation and T&D for a cross-section of firms in 1989. He finds that the total cost saving from integration for mean-sized companies (in terms of T&D and generation output) is 42 percent (p. 664). However, there are no significant economies of integration for either pure distribution or generation companies. The study also ranks the cost savings from integration. Lower O&M costs of power supply provide the biggest savings followed by lower operating expenses for T&D. Additionally, the author finds that certain holding structures can off-set losses from vertical integration but the same is not true for membership in power pools. Last the author finds that more nuclear capacity and higher capacity utilization are also associated with lower costs.

Arocena et al. (2009) find evidence for both horizontal and vertical economies of scope for a cross-section of firms in 2001. They estimate that vertically integrated firms save 4.3 to 9.7 percent of total cost. Estimates hardly depend on firm size in terms of distribution customers and generation output. But estimates depend on the generation outputs and the balance between distribution and generation activity. Divesting nuclear generation carries the greatest penalty followed by fossil-fuel and hydro. If the utility retains all nuclear capacity and divests fossil-fuel and hydro only, no significant loss in

economies of scope is incurred. Also, firms that have a greater generation to distribution ratio stand to lose less from divestiture. Generally, empirical estimates for economies of scope span a wide range and depend on various firm characteristics. This is not surprising as we would expect technology to change over time and to differ between firms.

Besides studies that characterize the production technology there is a literature that looks at firm efficiency, often using panel data. This literature is important because even if one found economies of scope, efficiency after divestiture could still go up or down. But according to Kwoka et al. (2010, p. 87) there is “no commonly held or understood hypotheses concerning the effect of restructuring on distribution [efficiency]”. Two efficiency studies that have similarities with our study are Kwoka et al. (2010) and Delmas and Tokat (2005). Both studies use a two-stage approach where firm-level efficiencies are estimated using Data Envelopment Analysis (DEA) and then these estimates are regressed on a set of explanatory variables including indicators for divestiture and restructuring. Kwoka et al. (2010) find no unequivocal evidence for a reduction in distribution efficiency following divestiture using a panel of 73 distribution companies for the years 1994-2003. They find that only mandatory divestitures have a statistically significant effect. For distribution efficiency (Farrell scores) based on total distribution costs they find that the efficiency gap with non-divested firms for all divestitures is only 0.003 points whereas for mandatory divestitures it is 0.055 points. Firms that divest voluntarily (or on a quid-pro-quo basis) might even slightly increase their efficiency.

Delmas and Tokat (2005) find evidence that divestiture decreases efficiency for the entire utility. Since they use a total cost approach (including generation, transmission, distribution and purchased power) they implicitly also study the net benefits of divestiture. Unfortunately, their results are obscured by several methodological shortcomings. First, due to a large number of input and output variables (seven and three respectively) 45 percent of firms are fully efficient. This is likely to complicate their second stage regression as there is little variance for the dependent variable. Also, they include cost of purchased power but do not control for changes in wholesale prices. Last, there are problems with the way in which they define indicator variables for integration and divestiture as explained by Kwoka et al. (2010, p. 90).

Goto and Makhija (2007) use stochastic frontier analysis to investigate the impact of deregulation on US utility efficiency between 1990 and 2004. Their output variable is revenue for the entire utility combining gas and electricity. They find that average efficiency between regulated and deregulated states starts to diverge around 1997 when deregulated states start falling behind regulated states. They also find that vertical integration (the ratio of purchased power to own generation) increases mean efficiency for the entire utility. Unfortunately, these results are difficult to compare to our own because the study combines electricity and gas.

One recent study that looks at the effect of restructuring on generation efficiency is Fabrizio et al. (2007). The authors find that restructuring (and its anticipation) decreases non-fuel production expenses by up to 5 percent which would fall short of the 10.8 percent reduction required according to Arocena et al. (2009) to off-set losses of vertical economies of scope.

It seems that studies of *technological* characteristics find stronger evidence for (potential) losses from divestiture than studies of *efficiency*. One reason might be that efficiency is not only driven by the characteristics of the technology but by various other drivers as well which might explain why firms divest voluntarily irrespective of losses in vertical economies of scope. There is a literature on firms' motivations to divest which suggests that even in the presence of economies of scope divestiture might be rational from a firm's perspective. Several authors stress the importance of relative transactions costs (i.e. make vs. buy), the institutional environment (in particular regulation), and management capabilities as determinants of divestiture; see for instance Harrigan (1985). Delmas and Tokat (2005) and Russo (1992) argue that there is a relationship between environmental uncertainty and vertical integration (which is not necessarily linear). High regulatory uncertainty can lead to vertical disintegration. Also, firms might diversify horizontally (into non-utility businesses) to loosen the grip of the regulator and divest to obtain the necessary funds.

4 Hypotheses

Unlike for studies that estimate economies of scope there is no theory that provides formal and testable hypotheses for the impact of divestiture on efficiency or the total cost-benefit. Nevertheless we propose the following four *ad hoc* alternative hypotheses based on our background knowledge and the empirical literature.

Hypothesis 1: divestiture reduces distribution efficiency.

A loss of economies of scope as well as restructuring costs would lead to lower (distribution) efficiency after divestiture because we assume one frontier for divested and non-divested firms. And, the efficiency loss should be greater for divested firms that generate less nuclear or hydro electricity as shown by Arocena et al. (2009).

Hypothesis 2: divestiture reduces the relative unit cost of power.

Restructuring and competition lead to more efficient production as shown by Fabrizio et al. (2007). Also, the possible elimination of automatic adjustment clauses and retail competition has increased incentives to put more effort into finding cheaper electricity.

Hypothesis 3: net benefits from divestitures are negative for the years immediately following divestiture but positive for later years.

So far the literature suggests that gains in generation efficiency fall short of compensating for losses in economies of scope. Nevertheless we believe that over time net benefits become positive because competition in generation develops and firms find ways to mitigate losses in economies of scope as suggested by Kwoka (2002).

Hypothesis 4: distribution costs and power sourcing benefits of divestiture are related at the firm level.

Kwoka et al. (2010) suggest that this point should be investigated given the emerging evidence. Under retail competition or performance based regulation firms might have an incentive to off-set losses in distribution efficiency through lower cost of power or other efficiency gains. However, simple cost reallocation from generation to distribution would produce results that confirm our hypotheses. The next section introduces the analytical framework and the econometric models that allow testing these hypotheses.

5 Analytical Framework

This section describes the construction of the efficiency indices, the divestiture indicator, and the overall net present value. It then introduces the regression models.

5.1 Measuring distribution, power sourcing, and transmission efficiency

Distribution efficiency. We estimate the efficiency of each distribution company as the ratio between weighted inputs and outputs in relation to observed best practice. Weights are chosen so as to maximize the efficiency for each firm given the best practice frontier. This is a frontier approach where the production technology determines the frontier and has the following characteristics: it is the same for all firms, it varies from year to year, and returns to scale are constant for a given year. Arocena et al. (2009) find that economies of scale at the generation and distribution stages are constant or decreasing. We use a Data Envelopment Analysis (DEA) estimator for this model (Charnes et al., 1978). This has the advantage that no behavioural assumption is required which makes it particularly suitable for rate of return regulated firms which are unlikely to minimize cost. A disadvantage of this non-parametric estimator is that it does not distinguish between (in)efficiency and unobserved heterogeneity but we account for firm-level heterogeneity in the second stage. We correct the DEA score for bias introduced by the fact that our sample does not necessarily contain the population best practice and the observed frontier lies below the “true” frontier using a bootstrap based bias correction proposed by Simar and Wilson (1998). It has the advantage of avoiding the boundary problem in the second stage regression as none of the efficiency scores is equal to one. And even though the bias-corrected efficiency scores tend to be lower than biased efficiencies this should not affect our results as such as we are only interested in the relative efficiency of divested firms vs. non-divested firms.

Our DEA model has two input and three output variables. The two inputs are the sum of distribution O&M, customer service expenses, and sales expenses (Opex) and capital expenses (Capex). Both include shares of general and administrative expense and general plant expense. We measure capital expense as current capital expenditure (i.e. plant additions). Kwoka et al. (2010) suggest that current expenditure has the advantages of being a controllable expense and being related to the investment program of the firm. It has the additional advantage of being observed at the firm level. Arocena et al. (2009) measure capital expense as the rate of return multiplied by the asset base.⁶ As we have no measure for rate of return we would have to assume a return common to

⁶ These authors obtain measures of rate of return from a proprietary data base. Our publicly available data does not contain this variable.

all firms. Our output variables are number of units distributed, number of customers, and distribution network length. For the first two the original FERC data is adjusted for retail competition. FERC data only accounts for bundled sales but after the introduction of retail competition in several states the actual number of units distributed and customers connected is higher than the bundled number because entrants use the network of the incumbent utility. Network length accounts for dispersion.

Unlike Farsi and Filippini (2005) we use monetary instead of physical input measures as we are interested in the monetary cost of divestiture. And unlike Kwoka et al. (2010) we follow Farsi and Filippini (2005) and do not aggregate O&M and capital expense to allow for different implicit input prices (i.e. weights). The data section below gives more detail on the measurement of these variables.

Power sourcing efficiency. We measure the relative efficiency of sourcing power using an index of unit cost. Unlike for distribution above the cost items are not weighted in such a way as to obtain the maximum efficiency score for each firm. Implicitly weights are identical across firms. Like the model for distribution efficiency this model also assumes constant returns to scale. We derive unit costs as follows. First, we calculate the total cost of power as the cost of own generation plus the cost of purchased power. The total cost of own generation is measured as the sum of O&M and capital expenses. For generation we measure Capex differently to make costs of own generation and purchased power more comparable. Similar to Farsi and Filippini (2005) we measure capital expense as the sum of interest, dividends, tax, and depreciation. Interest, dividends and tax are apportioned based on the share of production plant to total plant. Then the total cost of power is divided by the total number of units distributed. Finally, this unit cost is deflated by a state-level index for wholesale prices. This is an attempt to account for factors that are beyond the control of the firm. In particular, this normalization neutralizes the effect of market power in generation markets and the effect of fuel price changes, which is ignored by earlier studies. Essentially this is a performance index similar to the DEA score. But to make the interpretation more intuitive it is expressed in monetary units and not in relation to the best performing firm.

Transmission efficiency. Here we use a unit cost measure similar to the one for power sourcing. We measure transmission costs as O&M and capital expenses where the latter are measured as current plant additions. A major complication for transmission is the correct delineation of the transmission network and its costs and output. In order to account for the fact that many transmission networks comprise the assets of several companies we aggregate firm-level transmission costs at the state level and do the same for units distributed. We then divide the aggregate costs by the aggregate units distributed and obtain state-level transmission unit costs.

The literature distinguishes between the network and the total cost approach for efficiency measurement (Farsi and Filippini, 2005). Total net benefits depend on distribution, transmission, and power sourcing but we analyze efficiency separately. There are several reasons why we choose this approach. First, it better reflects the objectives of the regulator as after restructuring the regulator is mostly concerned with regulation of the network and no longer the control of generation (though some state regulators still set retail tariffs during transition periods). Also, this approach allows us

to quantify the net benefits of divestiture independently for distribution and power sourcing. Our approach makes several important assumptions. We assume that the distribution technology is independent of sourcing power. We do not allow firms to trade-off distribution and power expenses reflecting the situation of the newly divested firms rather than the industry legacy potentially overstating the benefits from divestiture.

5.2 Defining divestiture

We do not observe divestiture directly but infer divestitures from changes in the balance sheet (Kwoka et al., 2010). We record a divestiture when the book value of production plant drops by at least fifty percent year-on-year and the proportion of own generation of total requirements is at least twenty-five percent the year before divestiture. The firm counts as divested for all the years thereafter. Thus, we only account for the first but not subsequent divestitures for the same firm. Instead of using book values one could use physical generation capacity or actual generation output as proxies for divestiture. Having manually checked the data we believe that book value is the best measure for this particular data set. Our thresholds are somewhat arbitrary but follow Kwoka et al. (2010) who also use a fifty percent drop in plant value given a “substantial fraction” of own generation. Based on this single post-divestiture indicator we also derive an indicator for divesting firms *before* divestiture as well as a set of indicators for individual years *after* divestiture. The first of the individual indicators takes the value one for the year of divestiture; the second takes a value of one for the first year after divestiture and so on. For transmission a state counts as “divested” when the first firm divests in this state; and all subsequent years.

5.3 Measuring costs and benefits of divestiture

We calculate firm-level net benefits of divestitures by comparing the weighted costs between each divested firm and the mean for all non-divested firms. We do this separately for distribution, power sourcing, and transmission before summing across activities, firms, and years to arrive at a single net present value number for the sample of divestiture. The weights are efficiency measures (as defined above) allowing for multiple inputs and outputs as well as inefficiency. The average efficiency of all non-divested firms is our counterfactual. It is not a perfect counterfactual because there might be spill-over effects from restructuring states to non-restructuring ones (Fabrizio et al., 2007). We also, adjust the net benefits for any initial differences between divested and non-divested firms essentially using a difference-in-difference approach. This accounts for at least part of any endogeneity. Nevertheless, it is possible that divesting firms were more likely to benefit from divestiture due to some unobserved characteristics leading to an overestimate of the effect of divestiture.

Formally, for firms $i=1\dots N$ with $1\dots k$ divesting firms and $k+1\dots N$ non-divesting firms and $t=1\dots T$ years with $1\dots r$ years before divestiture and $r+1\dots T$ years after divestiture net benefit NB_{it}^A of activity $A=(D,P,T)$ for a divested firm $i\leq k$ in year $t>r$ equals the efficiency score of that firm θ_{it} minus the mean of the efficiency scores for all non-divested firms in that year divided by its efficiency score and multiplied with its total cost C^A . D, P, and T stand for distribution, power sourcing, and transmission respectively. From this first term in Equation (1) we subtract the firm’s equivalent average cost share for all the years prior to its divestiture. Thus if a firm had costs higher than non-divesting firms

prior to its divestiture this amount is subtracted from its ex-post cost difference. The opposite is true if its costs were lower to start with. For instance, if costs were higher before divestiture and stayed at the same level after divestiture the net benefit of divestiture would be zero.

$$NB_{it}^A = \left(\frac{\theta_{it}^A \frac{\sum_{i=k+1}^N \theta_{it}}{N-k}}{\theta_{it}^A} \right) C_{it}^A - \frac{\sum_{t=1}^r \left(\frac{\theta_{it}^A \frac{\sum_{i=k+1}^N \theta_{it}}{N-k}}{\theta_{it}^A} C_{it}^A \right)}{r} \quad (1)$$

Total cost for distribution is the sum of the two DEA inputs (Opex and Capex). The only difference for power sourcing is that we take the negative of the numerator of the first term to obtain positive numbers for the cases where the costs for divested firms are indeed lower. For transmission the only difference is that we calculate net benefits at the state instead of firm-level, i.e. transmission net benefits are the same for all firms in a given state and year. Intuitively, these net benefit measures compare the weighted costs between divested and non-divested firm. The weights depend on the activity and reflect its output mix. For distribution the DEA scores allow for weights that reflect several outputs.

Then, for each year we sum net benefits of distribution, transmission, and power sourcing across divested firms obtaining yearly total net benefits. Finally, we take the net present value *NPV* across all years from the first divestiture till the end of our sample (1997 to 2006) using a seven percent discount rate. This is the discount rate suggested by the US Office of Management and Budget.⁷

$$NPV = \sum_t \left(\sum_A \sum_i NB_{it}^A \right) (1+r)^{-t} \quad (2)$$

We are not aware of any previous literature that uses this exact approach.

5.4 Regression analysis

Besides being an input into the calculation of the aggregate net benefits the efficiency measures can be analyzed individually. We regress both distribution efficiency and the relative unit cost of power on the divestiture indicators and a set of control variables. Whereas such a second-stage regression is straightforward for cost of power as the dependent variable the literature does not agree on what is the most appropriate estimator when the dependent variable is a DEA efficiency score. Whereas most authors use Tobit or Least Squares estimators Simar and Wilson (2007) argue that these estimators do not account for the underlying data generation process and propose a

⁷ Source: <http://www.whitehouse.gov/omb/rewrite/circulars/a094/a094.html#8>, retrieved 25 January 2010.

rather complicated double-bootstrap estimator that accounts both for the bias in the original efficiency scores as well as the non-i.i.d. error correlations in the second stage regression. We use biased corrected efficiency scores and account for non-i.i.d. error structures in our second stage regression. This two-stage approach assumes that the explanatory variables do not influence the production technology but only the relative efficiency. Most panel data are plagued by non-i.i.d. error structures and there is a sizable literature on the appropriate choice of estimator (Kristensen and Wawro, 2007). Generally, the literature distinguishes between estimators that model the error structure and estimators that are robust to the error structure. Specification tests show that our data is serially correlated and heteroskedastic. We opt for a robust estimator potentially forsaking efficiency. A further complication with panel data is the likely correlation between unit fixed effects and slow-moving variables. This correlation produces a trade-off between stronger inference for variables that are slow-moving but deemed to be important and accounting for time-invariant panel heterogeneity.

Our variables for the various generation outputs are slow moving but at the same time we expect that firm characteristics and regulation are important factors that we cannot model explicitly. Therefore we compare models with and without fixed effects using two OLS estimators. First we use a standard Ordinary Least Squares Fixed Effects (OLS FE) estimator with robust standard errors. Second, we use an OLS estimator with panel-corrected standard errors (PCSE) and no fixed effects. These allow for panel heteroskedasticity as well as panel-specific autocorrelation (which the OLS FE does not).⁸

We run a total of nine regression models. Models 1 and 1a take the analysis of Kwoka et al. (2010) as a starting point. We add an indicator for divesting firms before divestiture, variables for the generation outputs, and we use a slightly different dependent variable. Model 1, Equation (3) regresses the unbiased Shephard distribution efficiency score (DEA-CRS) on an indicator for divesting firms after divestiture (POST), variables for the amount of fossil-fuel, nuclear, and hydro generation (FOSSIL, NUCLEAR, and HYDRO), the interaction of these variables with the post-divestiture indicator (FOSSIL*POST, NUCLEAR*POST, and HYDRO*POST), and the log of the ratio of residential sales to total sales (RESRATIO). Model 1a, Equation (4) adds an indicator for divesting firms before divestiture (PRE) and drops the firm-fixed effects. Note that the PRE indicator is not included in the fixed effects model as absent a constant it is collinear with the POST indicator. This specification allows the effect of divestiture to depend on the generation outputs for the different fuels as suggested by Arocena et al. (2009). They find that losses of vertical economies of scope are greatest for nuclear generation followed by fossil-fuel and hydro generation. But as we measure efficiency and not economies of scope our model does not distinguish between the effect of generation output on efficiency via economies of scope and other channels. Another obvious channel is systems design. For instance, hydro plants tend to be further away from load centres thus requiring longer distribution wires. Moreover, the effect might pick-up changes in economies of scope for both divested and non-divested firms that are not captured by the divestiture indicator to the extent that output is correlated with capacity. Economies of scope are likely to be continuous, something that our divestiture indicator does not capture. Figure 1 below shows that non-divesting firms also reduce the amount of own

⁸ The respective Stata commands are *xtreg* and *xtpcse*.

generation potentially suffering losses of economies of scope as well. Last, firms with a higher proportion of residential sales are likely to have higher costs because they have more connections which are the main cost driver for distribution (Arocena et al., 2009). Firm and year fixed effects are included as α_i and δ_t respectively (firm and year indices are omitted for all other variables for simplicity).

$$\begin{aligned} DEA - CRS = & \beta_1 POST + \beta_2 FOSSIL + \beta_3 NUCLEAR + \\ & \beta_4 HYDRO + \beta_5 FOSSIL * POST + \beta_6 NUCLEAR * POST + \\ & \beta_7 HYDRO * POST + \beta_8 \ln(RESRATIO) + \alpha_i + \delta_t + \varepsilon_{it} \end{aligned} \quad (3)$$

$$\begin{aligned} DEA - CRS = & \beta_1 PRE + \beta_2 POST + \beta_3 FOSSIL + \beta_4 NUCLEAR + \\ & \beta_5 HYDRO + \beta_6 FOSSIL * POST + \beta_7 NUCLEAR * POST + \\ & \beta_8 HYDRO * POST + \beta_9 \ln(RESRATIO) + \alpha + \delta_t + \varepsilon_{it} \end{aligned} \quad (4)$$

The null for Hypothesis 1 above implies for Model 1 that $\beta_1 + \beta_5 FOSSIL + \beta_6 NUCLEAR + \beta_7 HYDRO = 0$ or alternatively for Model 1a $\beta_2 + \beta_5 FOSSIL + \beta_6 NUCLEAR + \beta_7 HYDRO - \beta_1 = 0$. We evaluated both equations at the sample means for divested firms. Whereas Models 1 and 1a use a single indicator variable for divestiture Models 2 and 2a (not shown) use a total of eight indicator variables to indicate individual years following divestiture and thereby account for lags in the effect of divestiture. The POST variable in Model 1 and 1a above is replaced by eight indicator variables (POST1-POST8) where the first indicates the year of divestiture, the second the first year after divestiture and so on. All other variables are the same. The dependent variables in Models 3 and 3a (Equations (5) and (6)) are the log of the relative unit cost of power (PowUnitCost). The independent variables are similar to Model 1 and 1a. Again we allow the effect of divestiture to depend on the generation outputs. These models do not include the residential sales variable because power sourcing cost should not depend on who the customers are. Again Model 3 includes fixed effects and Model 3a includes the PRE variable but no fixed effects.

$$\begin{aligned} \ln(PowUnitCost) = & \beta_1 POST + \beta_2 FOSSIL + \beta_3 NUCLEAR + \beta_4 HYDRO + \\ & \beta_5 FOSSIL * POST + \beta_6 NUCLEAR * POST + \beta_7 HYDRO * POST + \alpha_i + \delta_t + \varepsilon_{it} \end{aligned} \quad (5)$$

$$\begin{aligned} \ln(PowUnitCost) = & \beta_1 PRE + \beta_2 POST + \beta_3 FOSSIL + \beta_4 NUCLEAR + \beta_5 HYDRO + \\ & \beta_6 FOSSIL * POST + \beta_7 NUCLEAR * POST + \beta_8 HYDRO * POST + \alpha + \delta_t + \varepsilon_{it} \end{aligned} \quad (6)$$

The null for Hypothesis 2 above implies for Model 3 that $\beta_1 + \beta_5 FOSSIL + \beta_6 NUCLEAR + \beta_7 HYDRO = 0$ or alternatively for Model 3a $\beta_2 + \beta_5 FOSSIL + \beta_6 NUCLEAR + \beta_7 HYDRO - \beta_1 = 0$ when evaluated at the sample mean for the divested firms. Models 4 and 4a (not shown) are similar to Models 2 and 2a in that they again replace the single divestiture dummy by a set of yearly indicators. Model 5, Equation (7) regresses the firm level net benefit of power sourcing (NB^P) on the net

benefit of distribution (NB^D) for divested firms using a quadratic form. We include year fixed effects only.

$$NB^P = \beta_1 NB^D + \beta_2 NB^D^2 + \delta_i + \varepsilon_{it} \quad (7)$$

The null for Hypothesis 4 above implies that net benefits are not related at the firm level and thus $\beta_1 + \frac{1}{2}\beta_2 \ln(NB^D) = 0$. Models 1, 2, 3, and 4 are estimated using OLS FE. Models 1a, 2a, 3a, 4a, and 5 are estimated using PCSE.

We are aware of several shortcomings of our data and our analytical approach. First, the analysis is necessarily short-run as our sample only covers six years after the main wave of divestitures around the year 2000 and only three years after the last divestiture we observe. This is a potential problem because we know that there have been various transitory arrangements which might bias the reported cost figures. In particular buy-back contracts with formerly integrated generation units might have been overly favourable which would lead us to overestimate the benefits of divestiture. Our treatment of transmission is not ideal because we cannot delineate individual transmission operations. However, we believe that the way we include it is sufficient to rule out that large costs of divestiture may be hiding in transmission. Also we omit certain variables. For instance we do not include input prices and therefore assume that firms are allocatively efficient but divestiture might lead to (temporary) allocative inefficiency. Also divestiture is likely to be correlated with other changes in regulation like the introduction of performance based regulation. Domah and Pollitt (2001) show that the costs of UK electric distribution companies increased with privatization but fell when incentive regulation was applied in earnest.

6 Data, Variables, and Summary Statistics

The data mainly comes from the regulatory accounts US utilities have to file with the Federal Energy Regulatory Commission (FERC). These filings are known as Form 1 and have to be submitted on an annual basis by utilities above a certain size. The data is publicly available on the FERC website. The Form 1 data is well established in the economic literature. Examples are Arocena et al. (2009) and Kwoka et al. (2010). The main advantage of this data set is that data is consistently available for a large number of variables, a large number of firms, and several years. Our data covers almost all major electric utilities with gaps. We observe distribution efficiency scores for 138 firms out of 144 major utilities as counted by Sappington et al. (2001).

Table 1 describes the variables. The appendix gives more detail on the construction of these variables as well as details on the sources. Distribution operating expenses (Opex) are measured as distribution operation and maintenance, customer accounts, customer service, and sales expenses plus a share of general and administrative expenses. The allocation key for the latter is based on the ratio of labour expenses for distribution, customer accounts, and sales to total labour expenses less general and administrative labour expenses. Opex is expressed in year 2000 dollars where the deflator is an index of state-level electricity distribution wages (or gas where electricity is not available). The index is based on the “Quarterly Census of Employment and Wages” series published by the Bureau of Labour statistics. Capital expenses (Capex) are measured as distribution plant additions plus a share of general plant additions. The allocation key is the ratio of distribution plant over total plant. Capital expense is expressed in year 2000 dollars where the deflator is a national US GDP deflator⁹. The outputs are units delivered (Units), number of customers (Customers), and network length (Network length). Since Form 1 only reports units delivered and number of customers for bundled service we adjust the data to take into account that with the onset of retail competition actual numbers tend to be higher than bundled numbers. For this purpose we add data from the Energy Information Agency (Form EIA-861) and the state public utility commissions (PUC). Both the EIA and PUCs report distribution service only numbers. Where we have data from both the EIA and the PUC we take the minimum. If we cannot obtain data from either the EIA or PUC we revert back to the FERC data.

The unit cost of power (PowUnitCost) is calculated as follows. Total cost of power sourcing is the sum of cost of own generation and purchased power. The former is the sum of operation, maintenance, and capital expense. Capital expense is the sum of interest, dividends, and taxes apportioned on the ratio of generation plant to total plant; plus depreciation. Total cost is divided by the units distributed (including resale). This unit cost is deflated (year 2000 dollars) by an index of state-level prices for industrial customers¹⁰ which serves as a proxy for a wholesale price index. A proxy is used because for some states there is no wholesale price for all years as wholesale markets were only introduced with restructuring.

The unit cost of transmission (TransUnitCost) is based on the sum of O&M and capital expenses. Transmission O&M is total transmission O&M expenses plus system control and load dispatching, and a share of general expenses where the allocation key is based on labour expenses. As system control and load dispatching is actually a generation item the key underestimates share of general expenses allocated to transmission. This is likely to cause an overestimate in the change in transmission costs at divestiture as generation costs decrease (and cost of power increases). As the data does not allow us to refine the key and as the bias is conservative we leave the key as it is. O&M expenses are deflated by the same wage deflator as distribution Opex above. Capital expenses are measured as current year plant additions plus a share of general plant additions where the allocation key is based on the ratio of transmission to total plant. The deflator for capex is again GDP. We sum total costs across all firms in a state and divide them by the respective sum of units distributed.

⁹ Source: <http://www.gpoaccess.gov/usbudget/fy09/hist.html>.

¹⁰ This data is taken from the EIA Electric Power Annual 2007, Table “1990 - 2007 Average Price by State by Provider (EIA-861)” which can be found at: http://www.eia.doe.gov/cneaf/electricity/epa/epa_sprdshts.html.

Table 1: Variable Measurement

Variable	Definition
<i>DEA Inputs</i>	
Distribution Opex	Distribution O&M + customer accounts + customer service + sales + share of general expense (m. US\$, 2000)
Distribution Capex	Current year distribution plant additions + share of general plant additions (m. US\$, 2000)
<i>DEA Outputs</i>	
Units	Total units distributed, adjusted for retail competition (thd. Mwh)
Customers	Total number of customers, adjusted for retail competition (thd.)
Network length	Total network length (thd. miles)
<i>2nd Stage Regression</i>	
DEA-CRS	DEA efficiency score for distribution (see inputs and outputs above)
PowUnitCost	Generation O&M + interest + dividends + tax + depreciation + purchased power expenses divided by bundled units distributed and indexed on a state-level industrial retail price (US\$/Mwh, 2000)
TranUnitCost	Transmission O&M + share of general expenses + current year transmission plant additions + share of general plant additions divided by bundled units distributed (US\$/Mwh, 2000), aggregated to state level
PRE	Pre-divestiture indicator: 1 if firm is going to divest; 0 otherwise
PDD	Post divestiture Indicator: 1 if year-on-year reduction in production plant value > 50% (and all subsequent years) and proportion of own generation > 25%; 0 otherwise
PDD1-PDD8	Yearly post divestiture indicators: PDD1 = PDD in first year of divestiture; 0 otherwise. PDD2 = 1 in second year of divestiture; 0 otherwise, etc.
RESRATIO	Ratio of residential sales divided by total sales, adjusted for retail competition (proportion)
Own generation	Proportion of own generation in total requirements (proportion)
FOSSIL	Fossil-fuel generation (m. Mwh)
NUCLEAR	Nuclear generation (m. Mwh)
HYDRO	Hydro generation (m. Mwh)
<i>NPV calculation</i>	
NET BENEFIT (Distribution)	Percentage difference in distribution efficiency between divested and non-divested firms times total distribution cost (m. US\$, 2000), Equation (1)
NET BENEFIT Power sourcing)	Percentage difference in unit cost between divested and non-divested firms times cost of power (m. US\$, 2000), Equation (1)
NET BENEFIT (Transmission)	Percentage difference in unit cost between divested and non-divested states times cost of transmission (m. US\$, 2000), Equation (1)
NPV	NPV in 1996 is the discounted (7%) sum of total net benefits across all divestitures

Table 2 provides summary statistics. It distinguishes between non-divested and divested firms. Just above 10 percent of our observations are for divested firms. The size of the distribution operations is similar for both types. The difference in generation output depends on the technology. Fossil-fuel based output is three times, and hydro output two times larger for non-divested firms. Nuclear output however is similar. The unit costs for power and transmission are similar but the distribution efficiency is lower for divested firms. When looking at the three DEA output variables it is obvious that we include utilities of all sizes which might be debatable especially as we impose constant returns on our distribution technology. Note that for the ratio of residential customers the maximum is above 1. As there are only very few observations greater than 1 we do not drop these. Table 3 gives the yearly count for each of the divestiture indicator variables. The third column effectively gives the count of divestitures by year as POST1 indicates the first year of divestiture only. Most divestitures occur between 1999 and 2001. Note that the total count of divestitures in the second column is somewhat greater than the number of observations for divested firms in Table 2 because some observations might be missing in the years after we recorded a divestiture.

For this type of analysis it is important to know the sampling procedure and the reasons why observations are missing. In principle we observe the population as FERC gathers data for all large utilities. However, in practice some observations are missing or dropped because they make no sense. For our final data set we observe that the proportion of missing values is greater for distribution than for power sourcing. Also, the proportion of missing values drops after about 2001 for distribution but stays constant for power sourcing. Unfortunately we do not know why this is the case. But as distribution contributes negatively to the net effect of divestiture this might lead to an overestimate of the benefits of divestiture. Last, the first year of divestiture tends to have more gaps in the data than subsequent years so that we observe only 18 out of 29 first year costs and benefits which would overestimate the benefit if costs are incurred in the first year of divestiture.

Table 2: Summary Statistics

	Non-divested				Divested			
	mean	sd	min	max	mean	sd	min	max
Distribution Opex (m. US\$, 2000)	121.44	172.31	0.39	1673.81	157.39	138.30	17.97	866.76
Distribution Capex (m. US\$, 2000)	71.38	102.34	0.09	797.46	82.41	100.82	8.58	679.17
Units (thd. Mwh)	15069.08	18728.72	13.08	103652.91	17777.36	15732.94	1718.20	92362.80
Customers (thd.)	570.16	769.94	1.73	5121.49	731.12	648.88	126.84	3738.63
Network length (thd. miles)	19.49	20.80	0.09	119.31	19.85	16.74	0.90	86.88
PowUnitCost (US\$/Mwh, 2000)	40.85	17.20	1.49	146.18	41.74	15.43	11.23	106.53
TransUnitCost (US\$/Mwh, 2000)	3.52	2.35	0.44	19.69	3.50	2.56	0.84	19.69
Own generation (proportion)	0.52	0.34	0.00	1.00	0.18	0.24	0.00	0.90
Fossil-fuel generation (m. Mwh)	9.83	12.54	0.00	79.72	1.37	3.17	0.00	18.38
Nuclear generation (m. Mwh)	2.96	7.11	0.00	79.42	1.29	2.60	0.00	12.42
Hydro generation (m. Mwh)	0.52	1.61	0.00	16.61	0.07	0.28	0.00	3.69
Res. Ratio (proportion)	0.35	0.11	0.03	1.14	0.33	0.09	0.00	0.81
Dist. Eff. (CRS)	0.69	0.15	0.21	0.96	0.59	0.18	0.25	0.91
Observations	1644				210			

Table 3: Count of Divestiture Dummies

Year	POST	POST1	POST2	POST3	POST4	POST5	POST6	POST7	POST8
1994	0	0	0	0	0	0	0	0	0
1995	0	0	0	0	0	0	0	0	0
1996	0	0	0	0	0	0	0	0	0
1997	2	2	0	0	0	0	0	0	0
1998	4	2	2	0	0	0	0	0	0
1999	14	10	2	2	0	0	0	0	0
2000	23	9	10	2	2	0	0	0	0
2001	30	7	9	10	2	2	0	0	0
2002	29	0	7	9	9	2	2	0	0
2003	30	1	0	7	9	9	2	2	0
2004	30	0	1	0	7	9	9	2	2
2005	30	0	0	1	0	7	9	9	2
2006	30	0	0	0	1	0	7	9	9
Total	222	31	31	31	30	29	29	22	13

Last we illustrate the impact of divestiture on the firm level sources of power. Figure 1 gives the proportions of own generation, as well as fossil-fuel, nuclear, and hydro generation of total requirements. Total requirements is the sum of own generation and purchased power. Note that the numbers are for generation output and not capacity.

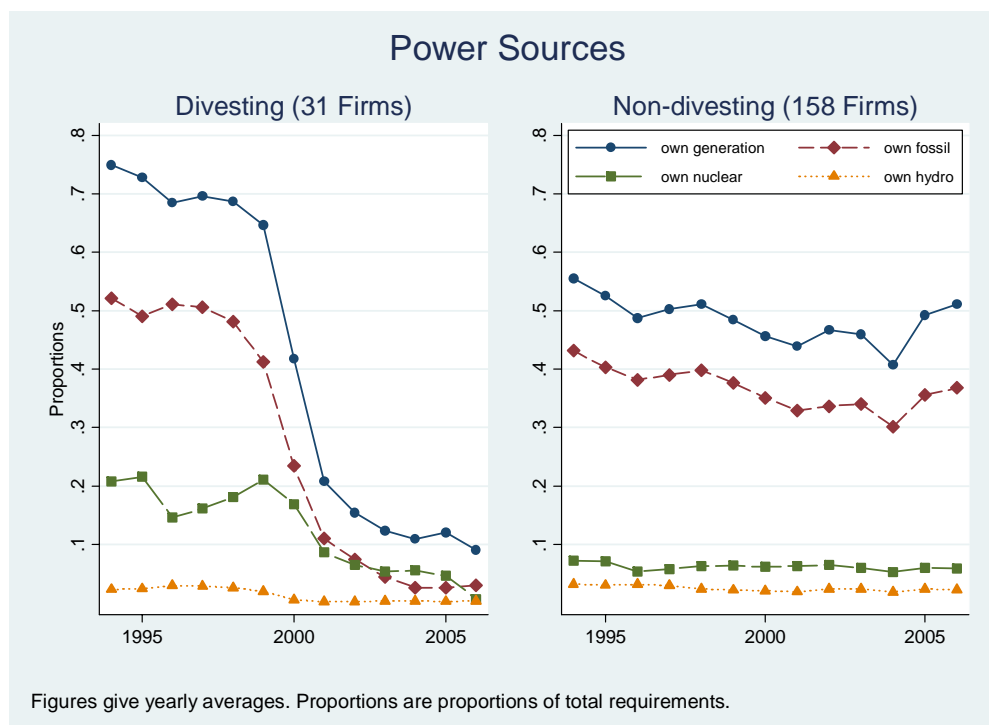


Figure 1: Power Sources

Whereas the left panel shows divesting firms the right panel shows non-divesting firms (before and after divestiture respectively). For divesting firms the average proportion of own generation drops from about 0.75 at the beginning of the sample to about 0.1 at the end. For non-divesting companies the proportion of own generation fluctuates around 0.5. For both types of firms fossil-fuel generation changes in line with own generation. Before divestiture divesting companies have about twice the amount of nuclear generation compared to non-divesting firms. However, at the end of the sample divesting firms divested almost all their nuclear and hydro generation. For non-divesting firms the proportion of nuclear and hydro generation is virtually unchanged over the sample period. It is interesting that up until 2004 non-divesting companies continuously reduce the amount of own generation but sharply increase generation thereafter. Also, before divestiture non-divesting firms actually rely more on purchased power than divesting firms.

7 Results

This section proceeds as follows. First, we describe the distribution and power sourcing efficiencies graphically. Second, we present the regression results for these efficiency scores. Third, we present the net benefit calculation. Last, we show the regression results for the correlation between power sourcing and distribution net benefits.

7.1 Graphical Description of Efficiencies and Costs

Figure 2 compares the yearly distribution efficiency scores of divesting firms to the yearly averages for non-divesting firms. For the divesting firms it distinguishes the period before (dot) and after (short dash) divestiture and marks the efficiency at divestiture (square dot). We observe that at the time of divestiture the majority of firms are less efficient than the average non-divesting firm. Also, it seems that the efficiencies of divested firms diverge after divestitures which might be taken as evidence that some firms adjust better to the new environment than others. Last, for all firms efficiency seems to be downward trending. Almost all efficiency scores dip abruptly in 2003 but we are not sure what explains this. The squares also highlight the distribution of divestitures across the years. Due to gaps in the data we do not have efficiency scores for the first year of divestiture for all divested firms. Therefore the number of squares is lower than the total number of divestitures we observe. The same is true for Figure 3 below. The first divestitures occur in 1997 and the last in 2003. Most divestitures occur during the years 1999 to 2001. Our regression models below only consider the average impact of divestiture. However, this figure and the next suggest that there are important (and possibly systematic) differences across divestitures. For instance, Figure 2 shows that later divestitures involve firms that that seem less efficient to begin with.

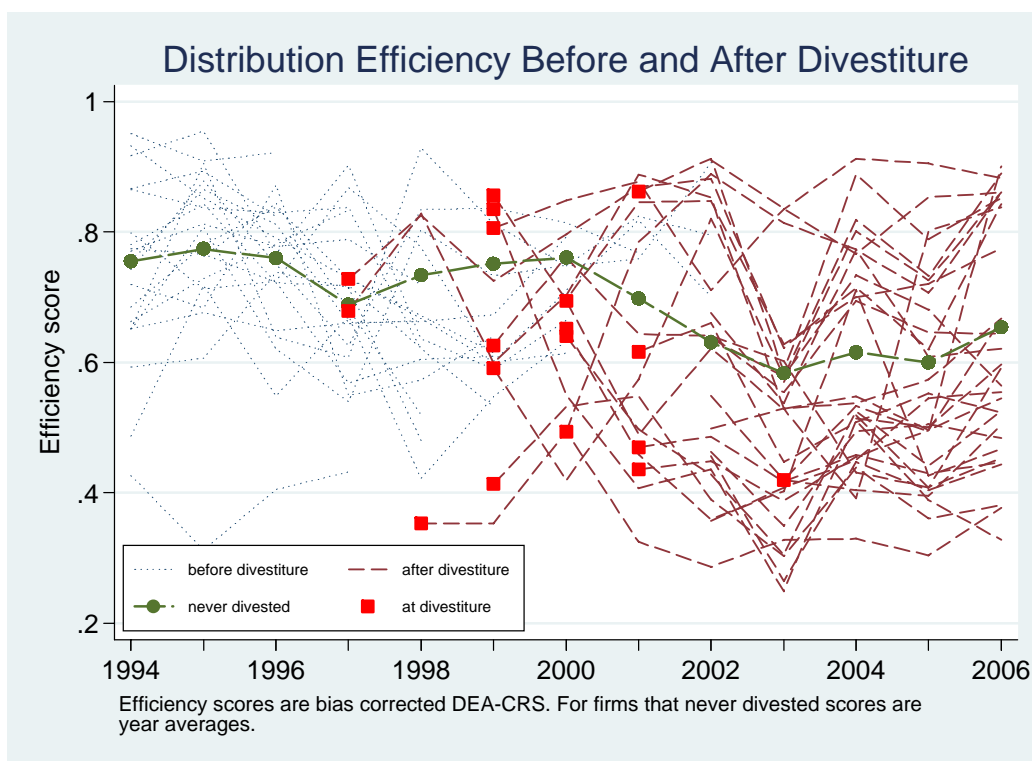


Figure 2: Distribution Efficiency Before and After Divestiture

Figure 3 maps the relative unit cost of power for the same set of divestitures. In most cases the cost of power at divestiture is higher than the average for non-divesting firms. In particular divestitures taking place in 1999 involve firms with very high costs.

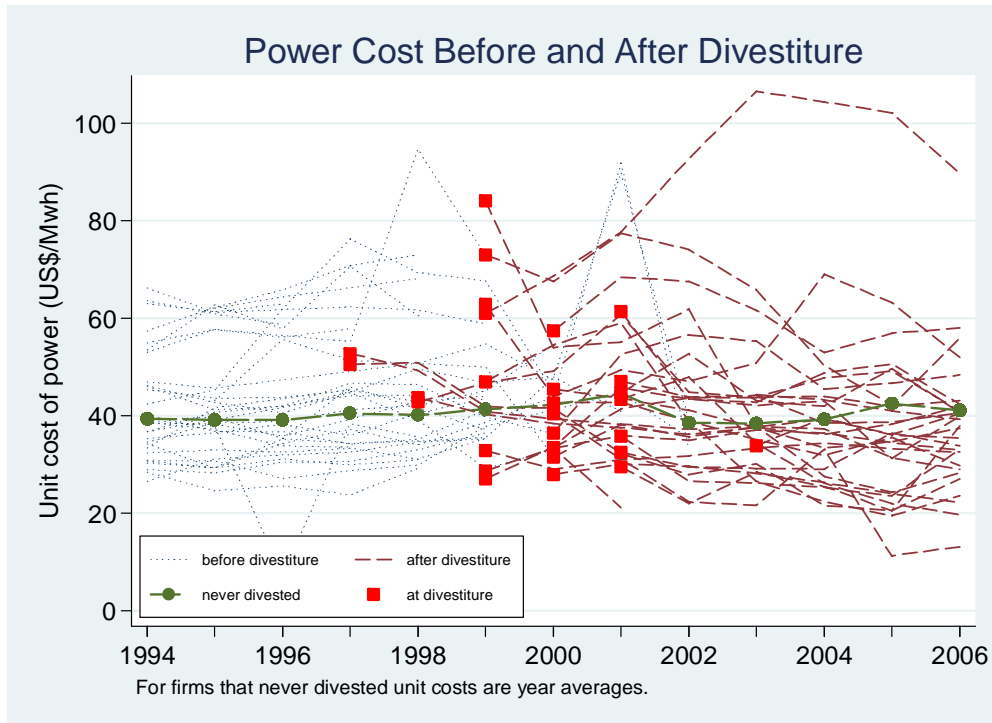


Figure 3: Power Cost Before and After Divestiture

After divestitures costs fall in line with non-divesting firms. Towards the end of our sample, costs for most divested firms fall below the average for non-divested firms. Last it seems to be the case that the lines in Figure 2 follow a more “chaotic” pattern than in Figure 3. There seem to be more abrupt swings in the distribution efficiencies than for the cost of power. It is likely that this is to some extent an artefact of our model (e.g. the difference in weighting between distribution and power sourcing). But it is also possible that this observation is driven by cost reallocation or differences in the state-level regulation for distribution. Federal regulation and later market discipline might produce stronger convergence for generation costs. Last, we illustrate the composition of costs for divesting firms. Figure 4 shows that the sum of power sourcing, distribution, and transmission costs has been falling for divesting firms. This is entirely driven by power sourcing costs as T&D costs have been fairly constant.

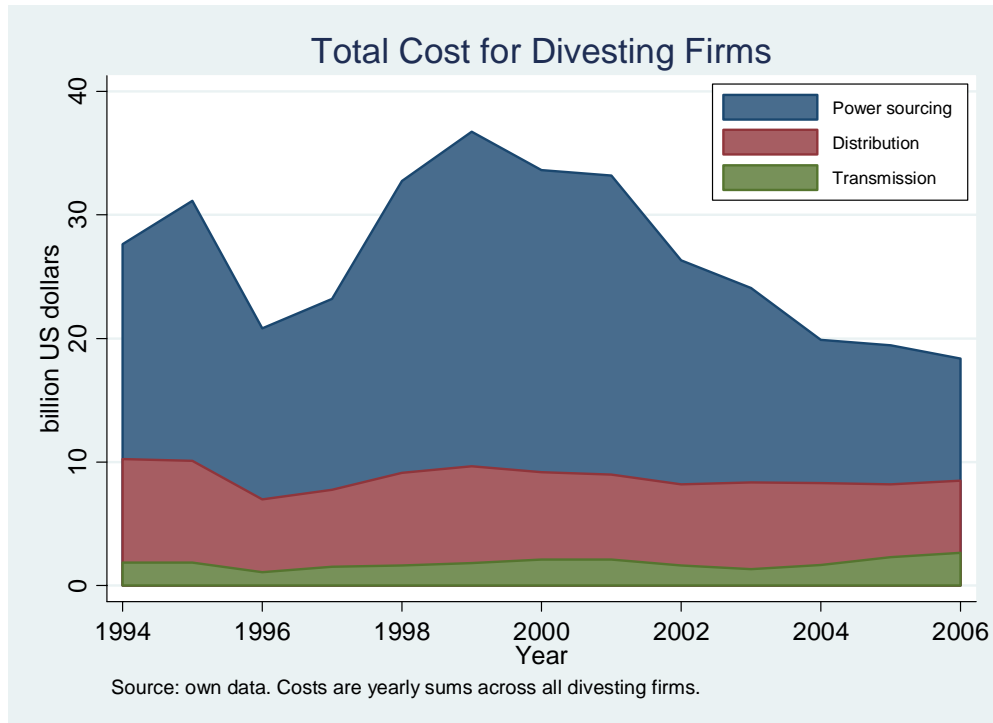


Figure 4: Total Cost for Divesting Firms

7.2 Determinants of Efficiency

Table 4 gives the results for Models 1, 1a, 2, and 2a. The dependent variable is the bias-corrected Shephard efficiency score (i.e. the inverse of the Farrell score used in Figure 2 and Figure 3 above). As the Shephard score ranges from 1 to infinity the effect on distribution efficiency is the opposite of the coefficient signs. Though broadly similar to the results of Kwoka et al. (2010) our results provide stronger evidence that divestitures lead to a loss in distribution efficiency. When modelling divestiture as a single regime dummy (Model 1 and 1a) we find that firms that divest completely (i.e. the interaction terms equal zero) are at least about 0.16 points less efficient. When fixed effects are excluded (Model 1a) the effect about doubles suggesting that there are important firm-level heterogeneities. Taken as a percentage of the constant which represents the average efficiency for non-divested firms the decrease is about 17 percent. For divested firms with average amounts of generation output the results hardly differ though divested distribution units with higher amounts of nuclear generation are slightly more efficient. Also the gap for the impact of divestiture between Model 1 and 1a narrows when taking generation output into account. Divesting nuclear is likely to carry a higher penalty compared to hydro and fossil-fuel generation. Also, divesting firms have a 0.045 points lower efficiency before divestiture (PRE) but the coefficient is insignificant at 10 percent. The influence of the generation outputs is broadly in line with the results of Arocena et al. (2009) who show that economies of scope depend on the up-stream generation outputs and that nuclear carries the highest penalty. For non-divested firms more fossil-fuel generation increases distribution efficiency

suggesting that “divestiture” also reduces efficiency for these firms. More hydro generation has the opposite effect for non-divested firms (nuclear has virtually no effect) suggesting this variable reflects system characteristics rather than economies of scope. Last, firms with a higher proportion of residential sales are less efficient. For Models 1 and 1a we can reject the null hypothesis that the linear combination of the coefficients including the before and after divestiture coefficients equals zero at a 5 percent level. In Models 2 and 2a the single post-divestiture dummy (POST) is replaced by a set of post-divestiture dummies for individual years (POST1-POST8). For both models a Wald test rejects the null hypothesis that all individual year coefficients are equal at 5 percent. These coefficients show that the difference between divested and non-divested firms is highest in the early years following divestiture. In the first year the effect is about double the average impact for Model 1 and 1a respectively. The gap closes and becomes statistically insignificant but re-emerges later. All other coefficients are virtually unchanged from Model 1 and 1a. As expected the inclusion of fixed effects seems to weaken the econometric significance of our slow-moving explanatory variables.

Table 4: Determinants of Distribution Efficiency

Model	(1)	(1a)	(2)	(2a)
	OLS FE	PCSE	OLS FE	PCSE
Variables	DEA-CRS	DEA-CRS	DEA-CRS	DEA-CRS
PRE(==1)		0.045 [0.41]		0.052 [0.32]
POST(==1)	0.157** [0.01]	0.292*** [0.00]		
POST1(==1)			0.249** [0.02]	0.418*** [0.00]
POST2(==1)			0.254*** [0.00]	0.349*** [0.00]
POST3(==1)			0.233*** [0.01]	0.350*** [0.00]
POST4(==1)			0.281*** [0.01]	0.381*** [0.00]
POST5(==1)			0.105 [0.35]	0.211*** [0.00]
POST6(==1)			-0.007 [0.92]	0.070 [0.33]
POST7(==1)			0.089 [0.22]	0.203** [0.01]
POST8(==1)			0.211* [0.09]	0.357*** [0.00]
FOSSIL	-0.002 [0.33]	-0.007*** [0.00]	-0.002 [0.26]	-0.007*** [0.00]
NUCLEAR	-0.002 [0.25]	0.001 [0.35]	-0.002 [0.31]	0.002 [0.23]
HYDRO	0.004 [0.72]	0.028*** [0.00]	0.004 [0.75]	0.028*** [0.00]
FOSSIL*POST	0.005 [0.62]	-0.005 [0.68]	0.001 [0.92]	-0.008 [0.54]
NUCLEAR*POST	-0.022* [0.08]	-0.033** [0.02]	-0.032*** [0.01]	-0.043*** [0.00]
HYDRO*POST	0.055 [0.83]	-0.086 [0.80]	-0.027 [0.91]	-0.209 [0.51]
ln(RESRATIO)	0.034** [0.02]	0.051*** [0.00]	0.033** [0.03]	0.051*** [0.00]
Constant	1.463*** [0.00]	1.475*** [0.00]	1.459*** [0.00]	1.466*** [0.00]
Observations	1126	1126	1126	1126
R-squared		0.80		0.81

Robust p-values in brackets: *** p<0.01, ** p<0.05, * p<0.1

Table 5 gives the results for Models 3, 3a, 4, and 4a where the dependent variable is the log of the relative unit cost of power. Note that the number of observations for this regression is much larger than for the regressions in Table 4 above which is due to the inclusion of generation only companies and fewer gaps in the data for the relevant variables. Unlike for distribution efficiency divesting firms have considerably higher (between 12.5 and 15 percent) unit costs before divestiture. When looking at Model 3a which includes the PRE variable we find that divestiture entirely eliminates the initial gap. For a complete divestiture the cost reduction is about 10 percent. For divestitures with average ex-post amounts of generation output the cost reduction is about 14 percent. The impact of divestiture depends on the generation outputs in the same way as for distribution above. Again divesting nuclear plant carries the largest penalty. The coefficient for hydro is small and insignificant at 10 percent. Fossil-fuel generation increases costs. We are not sure why this is the case. For non-divested firms all generation types have little impact on unit costs and most coefficients are insignificant at 10 percent. For Models 3 and 3a we can reject the null hypothesis that the linear combination of the coefficients including the before and after divestiture coefficients equals zero at 5 percent. Model 4 and 4a again replace the single indicator by a range of yearly indicators for divestiture. They reveal a similar pattern as in Model 2 though for Model 4a a Wald test does not reject the null hypothesis that all year coefficients are equal. This suggests that once we include the PRE variable accounting for individual years ex-post does not add information. The gap in unit cost with non-divested firms is highest at divestiture and narrows over time. For several later years the gap even turns negative. All other coefficients are almost unchanged from Model 3.

Table 5: Determinants of Generation Costs

Model	(3)	(3a)	(4)	(4a)
	OLS FE	PCSE	OLS FE	PCSE
Variables	ln(PowUnitCost)	ln(PowUnitCost)	ln(PowUnitCost)	ln(PowUnitCost)
PRE(==1)		0.125*** [0.01]		0.150*** [0.00]
POST(==1)	-0.105*** [0.00]	0.034 [0.48]		
POST1(==1)			0.056 [0.37]	0.139*** [0.00]
POST2(==1)			0.017 [0.68]	0.095** [0.03]
POST3(==1)			-0.001 [0.97]	0.086* [0.06]
POST4(==1)			-0.008 [0.84]	0.081* [0.10]
POST5(==1)			-0.068 [0.17]	0.027 [0.63]
POST6(==1)			-0.141** [0.02]	-0.039 [0.52]
POST7(==1)			-0.148** [0.02]	-0.032 [0.62]
POST8(==1)			-0.145** [0.03]	-0.033 [0.64]
FOSSIL	0.000 [0.80]	-0.006*** [0.00]	0.001 [0.46]	-0.006*** [0.00]
NUCLEAR	0.002 [0.21]	0.002 [0.47]	0.003* [0.09]	0.002 [0.45]
HYDRO	-0.011 [0.45]	-0.001 [0.94]	-0.010 [0.46]	-0.001 [0.95]
FOSSIL*POST	0.019*** [0.00]	0.013** [0.01]	0.010* [0.09]	0.008 [0.11]
NUCLEAR*POST	-0.046*** [0.00]	-0.037*** [0.00]	-0.055*** [0.00]	-0.043*** [0.00]
HYDRO*POST	0.003 [0.92]	-0.022 [0.59]	-0.026 [0.38]	-0.033 [0.42]
Constant	3.630*** [0.00]	3.566*** [0.00]	3.620*** [0.00]	3.557*** [0.00]
Observations	1854	1854	1854	1854
R-squared		0.97		0.97

Robust p-values in brackets: *** p<0.01, ** p<0.05, * p<0.1

7.3 Cost-Benefit Analysis

Table 6 gives the yearly means and sums for net benefits by year and activity. Columns one and two give the year and the cumulative count of the number of divestitures. Columns three and four give the yearly means and sums for the net benefits associated with distribution. Columns five and six give the yearly means and sums of net benefit associated with power sourcing. Columns seven and eight give the yearly means and sums of net benefits associated with transmission. Last, columns nine and ten give the yearly means and sums of total net benefits. Note that total net benefits are not necessarily the sum across columns because of gaps in the data. The last row gives the net present values of the sum across all years in 1996 using a discount rate of 7 percent to 2006. All divestitures together incurred a positive NPV of about \$11.3 billion. A simple sensitivity analysis shows that the NPV ranges from \$9.3 billion to \$14 billion for a 10 and 4 percent discount rate respectively. As net benefits increase with time lower discount rates produce higher NPVs. The overall NPV is about 5.5 percent of the total cost for all three activities, for all divested companies, for the years 1997 to 2006. The equivalent numbers for the distribution activity are \$-4.5 billion and 2.1 percent.

Looking at distribution only we see that yearly means fluctuate between 2 and -71 suggesting that costs vary across divestitures which is in line with the observation by Arocena et al. (2009) that there are no “one-size-fits-all” economies of scope. It is interesting to observe two years where distribution net benefits are not negative. Generally, the negative net benefits for distribution are compensated for by positive net benefits from sourcing power. Power sourcing benefits are low for the first couple of years but increase substantially towards the end of the sample. Power sourcing net benefits are positive for all years except one. Note that unlike the regression analysis the net benefit calculations do not account for potential measurement error and give equal weight to all observations and therefore fluctuate more widely (regressions give less weight to outliers). For the same reason the results are not always compatible. For instance, the positive distribution net present value in 1998 seems hard to reconcile with the regression results in Table 4. For transmission we only note that the numbers are relatively small in absolute terms compared with distribution and power sourcing. Unlike for distribution the net benefits for transmission are actually positive for most years though the large negative numbers for the last two years indicate that unlike for distribution and power sourcing net benefits might be trending downwards. A comparison of the absolute mean values for distribution and power sourcing stresses that the power sourcing side is much more important than the distribution side in monetary terms. For instance, for the last three years the power sourcing net benefits are between 3 and 5 times larger than the distribution net benefits. Comparing the results to Arocena et al. (2009) it is striking that whereas they estimate the average total cost saving from integration to be \$65 million in 2001 we find a *positive* net benefit of divestiture of more than double that amount for the same year.

Table 6: Net Benefits of Divestiture

Year	N	NET BENEFIT (Dist.)		NET BENEFIT (Power)		NET BENEFIT (Trans.)		Total NET BENEFIT	
		Mean	Sum	Mean	Sum	Mean	Sum	Mean	Sum
1997	2	-18	-37	129	258	26	26	137	248
1998	3	2	6	167	500	10	31	179	537
1999	9	-24	-219	-4	-35	9	56	-13	-126
2000	13	0	-4	60	722	18	143	66	715
2001	17	-59	-1000	189	3031	30	271	153	2241
2002	26	-39	-1010	81	2019	66	597	100	1446
2003	28	-71	-1981	99	2660	100	896	118	1397
2004	30	-33	-997	158	4426	14	101	150	3885
2005	30	-38	-1136	224	6056	-64	-576	136	4835
2006	30	-33	-986	160	4637	-58	-522	87	3686
<i>NPV (7%, to date)</i>		<i>-4531.02</i>		<i>14590.67</i>		<i>1022.34</i>		<i>11339.32</i>	

year 2000 million \$, N is number of divestitures (cumulative)

7.4 Power Sourcing vs. Distribution

Last, we investigate whether the net benefits on the distribution and power sourcing sides are related at the firm level. Because this regression model has only one explanatory variable we depict the results graphically instead of showing the standard regression results. Figure 5 plots the net benefits on the distribution side against the net benefits on the power sourcing side; and adds the quadratic prediction as well as a negative 45 degree line. Both terms of the explanatory variable are significant at 10 percent when year-fixed effects are included. The correlation is negative meaning that lower distribution net benefits are correlated with higher power sourcing net benefits. The null hypothesis that the linear combination of both terms equals zero is rejected at 5 percent. Importantly, very low net benefits for distribution are offset by positive net benefits on the power sourcing side. Also most points are above the 45 degree line confirming that net benefits on the power sourcing side outweigh net benefits on the distribution side at the firm level. Nevertheless, the correlation is rather weak as the majority of observations are clustered in the middle.

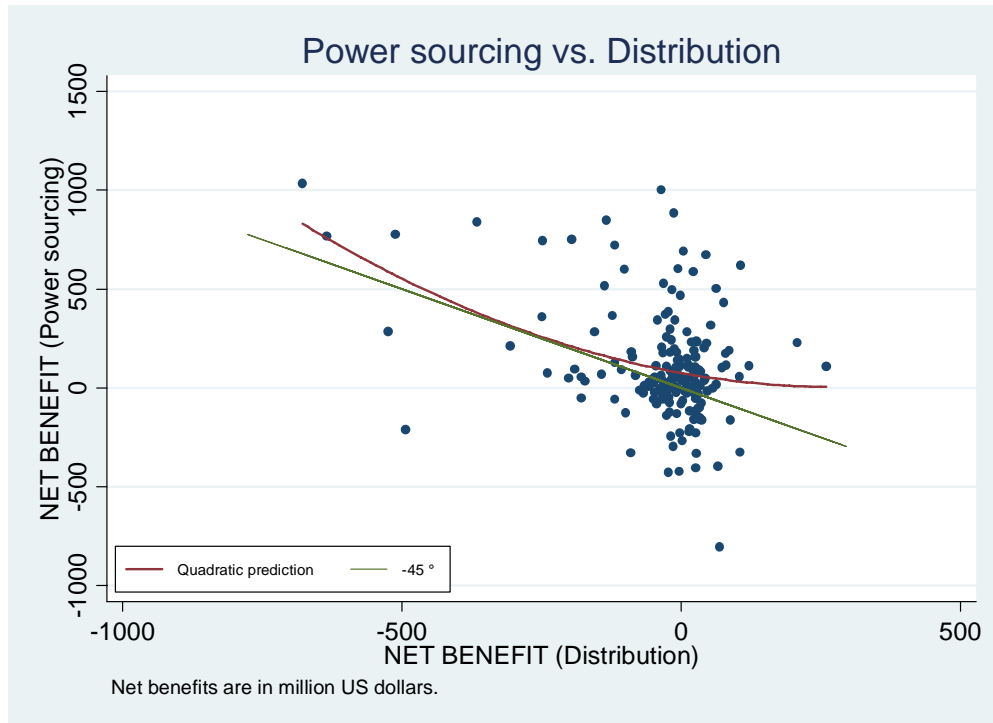


Figure 5: Power Sourcing vs. Distribution

Whereas the net benefit for the entire set of divestitures is associated with a large positive NPV the last result shows that this is not necessarily the case at the firm level.

8 Discussion

Our results show that US electric divestitures produce positive net benefits when taking into account distribution, transmission, and power sourcing. We find evidence that supports our first hypothesis that divestiture reduces distribution efficiency vis-à-vis non-divesting firms in line with the results of Kwoka et al. (2010). And less nuclear generation output leads to a greater loss of efficiency. To the extent that output is correlated with capacity this implies that divesting nuclear carries a higher penalty than other fuels. Also, the gap with non-divesting firms narrows over time. And even though we cannot establish causality between divestiture and a loss in efficiency we can rule out endogeneity as we control for the ex-ante difference between divesting and non-divesting firms.

There are several potential drivers for this result: loss of economies of scope, restructuring costs, and cost reallocation at divestiture. Unfortunately at this stage we can only speculate as to the relative importance of these drivers especially as we know from the literature that these are likely to vary across divestitures due to differences in firm characteristics and regulatory regimes. The fact that the gap in efficiency between divesting and non-divesting firms falls over time might indicate that part of the efficiency loss is due to one-off

restructuring costs. But it is also possible that losses in economies of scope are mitigated by organizational or technological change after divestiture. Finally, it is likely that the fall in efficiency for non-divesting firms is also partly responsible for the narrowing of the gap.

Comparing our results to Kwoka et al. (2010) we find economically and statistically more significant effects. This could be due to our larger data set or the different ways in which we measure some variables. One shortcoming compared to the above paper is that we do not control for mandatory divestitures. Kwoka et al. (2010) find that the impact of divestitures is worse when it is mandatory. But whether mandatory or not from a regulator's perspective the net benefits should be positive.

We find evidence that supports our second hypothesis that divestiture reduces the relative unit cost of power. Though divestitures (at least initially) merely equalize unit costs between divesting and non-divesting firms because the former had higher costs to start with. Again divesting nuclear generation carries an extra penalty. Similarly to distribution efficiency the gap with non-divesting firms decreases over time and possibly reverses towards the end of our sample. We cannot be entirely sure what drives this result. It is likely that losses in economies of scope are also incurred on the power sourcing side. Kwoka (2002) finds that losses in economies of scope have the largest impact on generation O&M followed by operating costs for transmission and distribution. Fabrizio et al. (2007) reach the conclusion that restructuring reduces generation costs. Thus efficiency gains might outweigh the loss of economies of scope on the power sourcing side, certainly for later years. We find a cost reduction even though we include cost of purchased power which includes generation profits and might have gone up when competition was introduced. Fabrizio et al. (2007) do not include this cost.

Our results support our third hypothesis. Indeed, net benefits are negative in some years though not necessarily in the early years after divestiture. Net benefits are positive at the end of the sample which is mainly driven by relatively lower costs of power for divested firms. A decade after the first divestiture the net present value is positive representing about 5.5 percent of the total costs of all divesting companies for our sample period. Interestingly, 5 percent is also the cost reduction found by for instance Newbery and Pollitt (1997) and Fabrizio et al. (2007) measuring cost differently but in related contexts.

Last, we find some evidence in support of our fourth hypothesis that net benefits for distribution and power sourcing are correlated at the firm level. The correlation is positive for most firms and in particular very low distribution net benefits are offset by positive power sourcing net benefits. Thus not only is the overall impact of divestitures positive but costs are on average offset at the firm level. Nevertheless not every single divestiture produces a positive net benefit. Given the uncertainty surrounding the drivers of costs and benefits it is not clear whether this can be attributed to firms' efforts to deliberately off-set costs or not.

9 Conclusion

The benefits of divestiture can be sizable but might depend on how and to what extent firms divest. Partial divestiture might be sensible especially when firms own nuclear generation. Several econometric studies on economies of scope warn regulators of the potential costs of vertical divestiture. When looking at the total cost of *actual* divestitures across time we find that the costs might well be worth it. Our approach highlights that, neither are all divestitures the same, nor do they cause simple one-off level changes in efficiency potentially limiting the insights that can be gained from standard regression analysis. Nevertheless our analysis complements rather than substitutes for these cost function studies. We suggest that more research should concentrate on individual cases which we ignore here. We know that in the US regulation, restructuring plans, and the nature of divestitures differ from firm to firm. If such diversity in regulation produces a wide range of outcomes as shown by our descriptive results some forms of regulation or organization are likely to be better than others and there is room for learning.

10 Appendix

Table 7 below describes the construction of the variables. All FERC data is taken from Form 1 which is freely available on the FERC website. All EIA data is taken from Form 861 which is available on the EIA website. Platts data is taken from hard copies of Platts “Directory of Electric Power Producers and Distributors”. In order to complement the EIA data we also obtained data from state public utility commissions (PUC). In several cases data for unit sales and customer numbers could be found on the PUC’s website. Where the data was not available online we contacted the PUC directly and in some cases obtained additional data. Note that for the FERC Form 1 data the line numbers might change across the years as new lines are added to the Form. The table below gives the lines for the year 2000. The power sourcing unit cost is deflated by an index of state-level industrial retail prices. The deflator is constructed as the retail price in a given year divided by the retail price in the year 2000.

Table 7: Variable Construction

Variable/Formula	FERC Name	Source	page-line
<i>Distribution Opex</i>			
DE+AE+CE+SE+key1*GE	DE TOTAL Distribution Expenses	FERC	322-126b
key1=(DW+CW+CSW+SW)/(TOW-AW)	AE TOTAL Customer Accounts Expenses	FERC	322-134b
key2=(GW)/(TOW-AW)	CE TOTAL Customer. Service and Information Expenses	FERC	322-141b
key3=(TW)/(TOW-AW)	SE TOTAL Sales Expenses	FERC	322-148b
	GE TOTAL Administration and General Expenses	FERC	323-168b
<i>Labour expenses</i>			
TOW	TOTAL Oper. and Maint.	FERC	354-25b
GW	Generation	FERC	354-18b
TW	Transmission	FERC	354-19b
DW	Distribution	FERC	354-20b
CW	Customer Accounts	FERC	354-21b
CSW	Customer Service and Informational	FERC	354-22b
SW	Sales	FERC	354-23b
AW	Administrative and General	FERC	354-24b
<i>Distribution Capex</i>			
<i>Plant</i>			
DA+key4*(GA)	DA TOTAL Distribution Plant Additions	FERC	207-69c
key4=(DP)/(TOP)	GA TOTAL General Plant Additions	FERC	207-83c
	DP TOTAL Distribution Plant	FERC	207-69g
	TOP TOTAL Plant	FERC	207-88g
<i>Units (total)</i>			
min(UE,UP)	UF TOTAL Sales of Electricity (bundled)	FERC	301-12d
or UF-UR if UE and UP missing	UR Sales for Resale	FERC	301-11d
	UE total unit sales of electricity (delivery)	EIA	n/a
	UP total unit sales of electricity (delivery)	PUC	n/a
<i>Units (residential)</i>			
min(RUE,RUP)	RUF Residential Sales (bundled)	FERC	301-2d
or RUF if RUE and RUP missing	RUE residential unit sales of electricity (delivery)	EIA	n/a
	RUP residential unit sales of electricity (delivery)	PUC	n/a
<i>Customers</i>			
min(CE,CP)	CF TOTAL Sales of Electricity (bundled)	FERC	301-12f
or CF-CR if CE and CP missing	CR Sales for Resale	FERC	301-11f
	CE number of customers (delivery)	EIA	n/a
	CP number of customers (delivery)	PUC	n/a
<i>Network length</i>			
	ND Distr TOTAL Miles	Platts	n/a
<i>PDD</i>			
	PP TOTAL Prod. Plant	FERC	207-42g
<i>Generation O&M</i>			
PE-OE+PPE+(key2)*GE	PE TOTAL Power Production Expenses	FERC	321-80b
	OE TOTAL Other Power Supply Exp	FERC	321-79b
	PPE Purchased Power	FERC	321-76b
<i>Generation Capex</i>			
key6*(NI+TO+ITF+ITO+DP+DC)+PD+key6*(GC)	NI Net Interest Charges	FERC	117-64
	TO Taxes Other Than Income Taxes	FERC	114-13e
	ITF Income Taxes - Federal	FERC	114-14e
	ITO Income Taxes - Other	FERC	114-15e
	DP TOTAL Dividends Declared-Preferred Stock	FERC	118-29c
	DC TOTAL Dividends Declared-Common Stock	FERC	118-36c
<i>General Plant Capex</i>			
key5*(NI+TO+ITF+ITO+DP+DC)+GD	GC		
key5=(GP)/(TOP)	GP TOTAL General Plant	FERC	207-83g
key6=(PP)/(TOP)	<i>Depreciation</i>		
	PD Production	FERC	336-(2-6)
	GD General	FERC	336-9
<i>GenUnitCost</i> (Generation O&M+Generation Capex)/UF			
<i>Transmission O&M</i>			
TE+SC+key3*GE	TE TOTAL Transmission Expenses	FERC	321-100b
	SC System Control and Load Dispatching	FERC	321-77b
<i>Transmission Capex</i>			
TA+key7*(GA)	TA TOTAL Transmission Plant Additions	FERC	207-53c
key7=(TP)/(TOP)	TP TOTAL Transmission Plant	FERC	207-53g
<i>TransUnitCost</i> (Transmission O&M+Transmission Capex)/UF			
<i>Ratio Res. Sales</i> Units (residential)/Units (total)			
<i>Own generation</i>			
NG/(NG+P)	<i>Power sources</i>		
	NG Net Generation	FERC	401-9b
	P Purchases	FERC	401-10b
<i>Nuclear</i>			
Nu	Nu Nuclear	FERC	401-4b
<i>Hydro</i>			
HC+HP	HC Hydro-Conventional	FERC	401-5b
	HP Hydro-Pumped Storage	FERC	401-6b
<i>Fossil</i>			
Fo	Fo Fossil-fuel	FERC	401-3b

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