Economic Impacts from Rate Increases to Non-DSI Federal Power Customers Resulting from Concessional Rates to the DSIs

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Executive Summary

Our charge in this study was to look at the consequences for the rest of the regional economy if non-DSI purchasers of wholesale power were required by the Bonneville Power Administration to pay higher electricity rates in order to fund DSI electric rates lower than the incremental cost of acquiring the electricity needed to serve that load. The magnitude of such a DSI rate subsidy is uncertain. It would depend on the quantity of electricity subsidized, and on the difference between the incremental acquisition price and the price at which the power is sold to the DSIs. In our analysis the annual subsidy is assumed to be $150 million.

Our modeling is based on an input-output model for the Pacific Northwest (PNW) region, including Oregon, Washington, Idaho and the western portion of Montana. Using this model as the starting point, we produced short-run and long-run model analyses.

Our short-run model assumed that the non-household sectors had a perfectly inelastic demand for electricity. The impact to business and industrial users was assumed to be a loss of owners' income, and the impact to government was assumed to be a reduction in payroll. Households, faced with this income loss and higher prices, were assumed to reduce consumption. This initial impact is assumed to propagate through the regional economy with further rounds of job losses and value added losses. The short-run model result is a total value added loss of $182.8 million per year and a total employment loss of 2,235 jobs throughout the regional economy.

Table ES1

Short-Run and Long-Run Employment and Value Added Effects of Higher Electric Rates to Non-DSI Electricity Users

	Direct	Indirect	Total
Short-Run			
Value Added ($ million per year)	-$77.4	-$105.4	-$182.8
Employment (# of jobs)	-287	-1,948	-2,235
Long-Run			
Value Added ($ million per year)	-$41.3	-$118.6	-$160.0
Employment (# of jobs)	-720	-2,103	-2,823

Our long-run model assumed somewhat more flexibility in responding to electricity price increases. Demands for output of the commercial and industrial sectors was assumed to have unitary elasticity – so while prices would increase somewhat in response to higher electricity prices, production levels would fall by the same amount, and total revenues would remain unchanged. The long-run model results show somewhat less value added loss per year, $160.0 million, and a bit more job loss, 2,823 jobs, than the short-run model.

We discuss possible reasons why the real-world flexibility that electricity users have in responding to higher prices might have caused our rather rigid models to under- or over-estimate the true value added and income effects. We conclude that there are arguments for both under- and over-estimation, and that our models probably take a reasonable middle road. We do note that as the size of the DSI rate subsidy gets larger, it takes larger electricity price increases to the non-DSU electricity users to balance BPA's budget. The higher price increases make it more likely that some firms will reduce their production levels or shut down. Thus at high subsidy levels, our models may underestimate the loss of employment and value added.

Our conclusion from our modeling is that if a DSI rate subsidy of $150 million is passed back to all non-DSI customers in the form of higher electric rates, the result would be a value added loss of $160 million to $180 million per year and an employment loss of at least 2,200 to 2,800 jobs. This potential significant loss of employment and value added from higher electricity prices to non-DSI consumers needs to be seriously weighed by policy-makers before any decision is made to provide rate subsidies to the DSIs.

One further conclusion should be noted. Our model did not disaggregate the effects of the price changes by region. However, if the model had allowed this level of detail, it would have shown that the effects of the DSI rate subsidy differ considerably between different parts of the PNW. The price increases were assumed to be borne by non-DSI electricity users all across the BPA service area. However, the job and value added benefits from the aluminum industry would be concentrated in the sub-regions near the smelters. The large parts of the BPA service area that are distant from smelters would bear significant costs from a DSI rate subsidy, but reap few benefits.

Introduction

The purpose of this project is to analyze the impact on other electricity consumers in the Northwest if the direct service industrial customers (DSIs) are supplied by Bonneville Power Administration (BPA) with up to 560 average megawatts (aMW) of power beginning in FY2011 at rates that are equivalent to BPA's priority firm rate, which is expected to be less than the incremental cost to BPA of acquiring that electricity. It is expected that such sales of power below the marginal cost of acquiring that power would result in a cost which would have to be met by rate increases to other electricity users in the BPA service area. The Public Power Council commissioned this study as input to Bonneville Power Administration discussions about this topic.

The PNW aluminum industry has faced serious financial difficulties in recent decades. International factors including globalization contributed first to weak world prices for aluminum metal. Increased electricity prices and electricity supply shortages in the PNW severely squeezed the industry, peaking in 2001.[1] More recently very high prices for alumina, the primary raw material (besides electricity) to aluminum production, have continued to plague the industry. Out of ten aluminum smelters in the region with a total potential demand of 3,150 aMW, only three of the lowest cost smelters are presently operating, with demand totaling about 300 aMW.

While BPA is not legally obligated to provide firm power contracts to the DSIs, it currently has agreed to provide up to 320 MW to Alcoa, up to 140 MW to Columbia Falls, up to 100 MW to Golden Northwest and 17 MW to Port Townsend Paper Company, for a total commitment of up to 577 MW for the years 2006 through 2010[2]. Presently these users are paying flat undelivered rates designated as "IP-TAC A and B" (Industrial Power, Targeted Adjustment Clause). The "A" rate is presently $30.70 per MWH and the "B" rate is $32.60 per MWH[3], including the effects of various surcharges levied on most of BPA's rates during the 2002-06 rate period.

Present electricity demand by the DSIs is substantially below the amounts that BPA has announced a willingness to sell. Table A1 shows that in 2005 BPA sold electricity valued at $82.5 million to the DSIs, which at the prices in the previous paragraph would have been 297 aMW. The table also shows that in 2006 BPA has contract obligations to sell 271 aMW to the DSIs. Sales in the first calendar quarter of 2006 totaled $21.3 million, or about 307 aMW[4].

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[1] Appendix A to the Council's 5th Power Plan contains a good summary of the status of the PNW aluminum industry, including forecasts of electricity demand. This document is available on the web at http://www.nwcouncil.org/energy/powerplan/plan/Appendix%20A%20(Demand%20Forecast).pdf Another good (although more dated) information source on the aluminum industry is the March 2001 report of the BPA Northwest Aluminum Industry Study Team http://www.bpa.gov/power/pl/aluminumstudy/ReviewSummary.pdf

[2] These quantity commitments come from an article in the Oregonian "BPA Fixes Contracts as 577 Megawatts" by Jonathan Brinkman, July 2, 2005, http://www.fwee.org/news/getStory?story=1390

[3] From BPA's posted average rates, found at http://www.bpa.gov/power/psp/rates/current.shtml

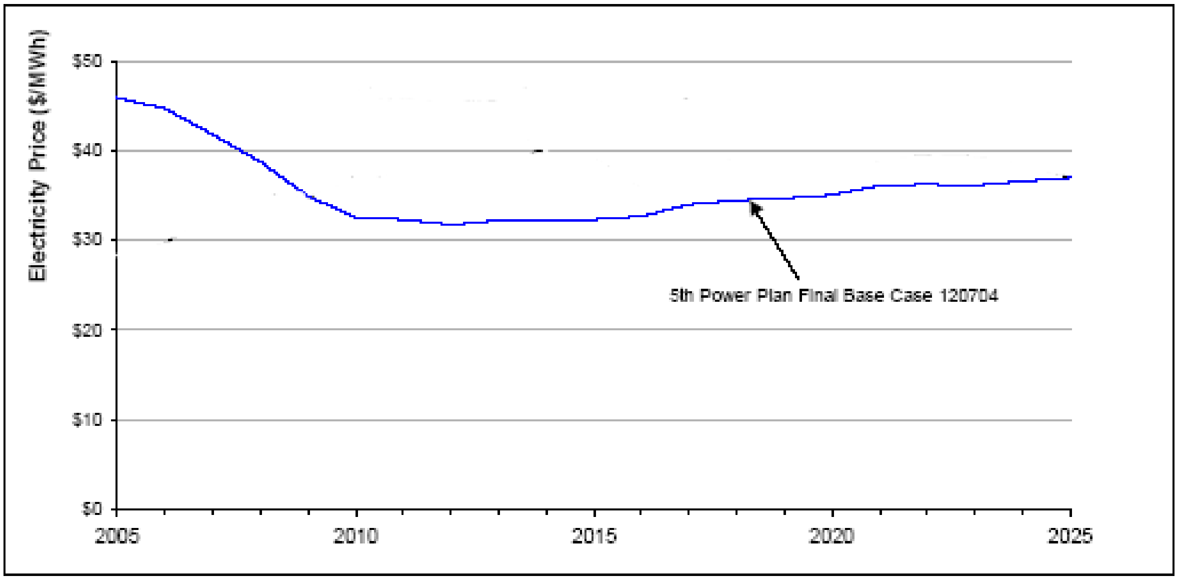
[4] From the BPA 2nd Quarter 2006 Financial Report http://www.bpa.gov/corporate/Finance/q_report/06/06-2qtrly.pdf

The Council's 5th Power Plan forecast for DSI demand in 2010 is 958 aMW, which implies considerable recovery from present conditions. Presently DSI demand is about 1/3 this level. Meeting the 958 aMW demand level would require some combination of electric costs lower than BPA's current rates, higher aluminum metal prices, or lower alumina prices.

The Possible Magnitude of the DSI Rate Subsidy

The magnitude of the possible DSI rate subsidy starting in 2011 is uncertain. As noted above, the quantity of the concessional DSI sales is very uncertain, although the 560 aMW current obligation to the aluminum industry would seem to be a reasonable starting point[5].

The dollar magnitude of the subsidy would also depend critically on the difference between the BPA priority firm rate and the incremental cost to BPA of acquiring that electricity. The Council's 5th Power Plan (Appendix C) presents the following forecast Mid Columbia electricity spot prices:



The Council forecast is based on assumptions that fuel prices (especially the price of natural gas) will decline from their highs in recent years. Under this assumption, spot market prices would decline to a marginal cost of generation of about $33 per MWh by 2011[6].

[5] This is also the amount noted in Paul Norman's March 10, 2006 letter announcing the BPA study: http://www.bpa.gov/power/pl/regionaldialogue/03-30-2006_dsi_letter.pdf

[6] This study includes prices and dollar values at several points in time, for example historic power sales in 2004 and 2005 and electricity prices for 2006 and 2011. For simplicity in the short time we had available for the analysis, we have chosen to ignore the possible but uncertain effects of inflation. We have not attempted to inflate or deflate these figures to a common base time period.

Another measure of the future incremental cost that BPA might face to acquire the additional power it would need to serve these DSI loads comes from what the investor-owned utilities expect to pay for their future power purchases. PacifiCorp publishes its avoided-cost price (which it agrees to pay to buy power from Oregon cogeneration and other power producers of 10,000 KW or less). The current avoided cost figure for power delivered in 2011 is 6.54 cents per kWh on-peak and 4.57 cents off-peak,[7] [8] Given that 96 out of 168 hours in each week are considered on-peak, the weighted average cost of this power is $57.68 per MWh

($0.0654 * 96 / 156 + $0.0457 * 72 / 168) * 1000 = $57.68

The rate at which this power might be sold to the DSIs is also in question. Presently the DSIs pay rates averaging about $31.70 per MWh – somewhat above the present "shaped" firm power rate of $29.10 per aMW, and well above the current "flat" firm power rate of $25.80 per aMW. Since the DSI demand is essentially flat (meaning that it varies little over time) they will presumably argue for the $25.80 rate. Since that would result in the largest subsidy, we will use that as a limiting case in the analysis that follows.

Given these numbers, one can get an idea of the size of the possible DSI subsidy. Using the Council's forecast of a Mid Columbia spot price of about $33 in 2011 as the acquisition price, and $25.80 as the price at which the power would be sold to the DSIs, gives a difference of $7.20. Applying this to 560 aMW and 8,760 hours per year gives an annual DSI subsidy of:

($33.00 - $25.80) * 560 * 8,760 = $35,329,320

Alternatively, if PacifiCorp's recent avoided cost filing is a better predictor of the cost of acquiring this power, then the subsidy would be:

($57.68 - $25.80) * 560 * 8,760 = $156,378,755

Obviously, there is considerable uncertainty about both the quantity of electricity that might be subsidized, the cost that BPA would face in acquiring that power on the regional electricity market, and the price at which this power might be sold to the DSIs. In the analysis that follows, we will use $150 million as the assumed magnitude of the subsidy. We will also discuss how that assumption affects our results: how the results would change if the subsidy were less than, or more than, $150 million.

[7] From Pacific Power and Light Company Schedule 37, July 12, 2005, http://www.pacificorp.com/Regulatory_Rule_Schedule/Regulatory_Rule_Schedule55260.pdf

[8] It is possible that the Council's forecast is a "Mid-C Hub" price, whereas PacifiCorp's is "at the meter", which will be higher because it includes transmission losses from Mid-C to the retail meter: PacifiCorp is able to avoid both the purchase of energy at Mid-C and the major variable cost associated with transmission and distribution of energy to retail loads. In the short time available for our study we have not attempted to untangle these assumptions.

The Impacts of a DSI Rate Subsidy on Other Electricity Consumers

BPA is required by law to price its electricity and other services to cover its costs. If the DSIs are granted a rate that is less than the incremental cost of acquiring their block of power, then these added rates will have to be woven into the rates charged to other regional electricity users. One might characterize this as a "tax" on the other users.

Some of the other users are probably immune to this tax. The rates charged to US Bureau of Reclamation projects and a few other federal entities are based on long-term contracts, and are not likely to be affected. This leaves power sales to non-DSI and non-federal entities to absorb most of the tax. In practice this will be mostly the "public" power utilities – municipal utilities, the Rural Electric Associations (REAs) the Public (and People's) Utility Districts (PUDs), and the Municipals (MUNIs). Numbers provided by NPCC staff (Table A1) indicate that the publicly owned utilities account for about 44% of total non-DSI electricity sales volume in the Pacific Northwest, and about 82% of BPA's non-DSI electricity sales revenues.

BPA's non-DSI power sales revenues totaled $2,107 million in 2005[9]. A $150 million DSI rate subsidy, if passed back equally as a tax to all these other users would amount to a 7.1% increase in rates:

$150 million / $2,107 million = 7.1 %

If it were passed back only to the publicly owned utilities (excluding the federal entities with long-term contracts and the investor owned utilities who now buy mostly non-firm power from BPA) from whom BPA received $1,717 million in revenue in 2005, the resulting rate increase would be somewhat less than 8.7%.

$150 million / $1,717 million = 8.7%

The "somewhat less" is because PGE and PacifiCorp both have firm power purchase agreements with BPA (although PGE's is going to expire fairly soon). PacifiCorp's contract rate is tied to BPA's average system cost, so presumably would increase if BPA subsidized the DSIs, reducing the amount that would need to be passed to the publicly owned utilities.

If the DSI rate subsidies are less than the $150 million assumed here, the required rate increases for everybody else would be proportionately smaller. However this works out though, we are talking about significant rate increases to non-DSI customers. These rate increases would be large enough that we would expect them to have real, measurable impacts on the non-DSI sectors of the regional economy.

[9] The revenue numbers come from page 37 of the BPA 2005 Annual Report, http://www.bpa.gov/corporate/Finance/A_Report/05/AR2005.pdf

Estimating the Economic Impacts of Rate Increases for Non-DSI Customers

Economic Modeling Specialists, Inc. (EMSI) builds regional Input-Output models for use in estimating economic impacts of alternative scenarios or policies.[10] For this study EMSI built a 468 sector model of the economies of Washington, Oregon, Idaho and Western Montana (the "Northwest"). This model region closely approximates the region within which the BPA service is contained.

We use this model to develop two alternative ways of looking at the impact of these electric rate increases on BPA non-DSI customers. We characterize these applications as a short-run model and a long-run model

The Short-Run Model

The short-run is characterized as a time period short enough so that capital assets of the electricity consuming business or household are fixed. In practice we tend to think of the short-run as measured in months or perhaps a year or so. The time period is too short for businesses to invest in new more energy efficient machinery or alternative technologies, and too short for households to buy new appliances or switch heating systems.

For modeling simplicity our short-run model adopts a rather extreme interpretation of what can be done in the short-run. The model assumes that the quantity of electricity demanded by all sectors except households is unchanged in the face of the expected price increases. In the language of economists, our short-run model assumes that non-household electricity demand is perfectly inelastic – or that the price elasticity[11] of demand is zero. Using this zero elasticity assumption means that business and industrial electricity users continue to use the same amount of electricity and continue to operate at the same level and produce the same output which they sell for the same revenue[12]. Because they have to pay more for their electricity purchases, this reduces their owners' income (measured as a change in value added[13]). Since the government

[10] See the "Appendix on the EMSI IO Model" at the end of this report.

[11] Elasticity is defined as the percent change in quantity of electricity demanded for a one percent change in price. If elasticity were -0.2, for example, then a 1% increase in price would result in a 0.2% decrease in quantity demanded.

[12] One of the reasons why we adopted the modeling assumption of perfectly inelastic demand is that this assumption is consistent with the Input-Output model assumption of a fixed (Leontief) input mix. That is, the I-O model assumes that industries do not change their mix of inputs in response to price changes.

[13] Value added is defined as labor income (equal to the sum of wages, salaries and proprietors' incomes) plus a collection of non-labor or "owners' incomes," including mainly profits and rents. For our short-run analysis, we assume that only owner's incomes, and wages in the case of government sectors, change in response to the electricity price increase.

sector does not have "owners" to absorb the effect of higher electricity prices, we assume that they respond by reducing payrolls[14].

Households are hit by the electricity price increase in three ways. First, the loss of value added in the business and industrial sectors means that this lost owners' income will result in less consumption spending by owners' households. Second, the loss of government payroll reduces the income and consumption spending of the households of government workers. Third, all households will have to pay more for the electricity they consume, effectively reducing their "real" income. With reduced incomes and higher electricity prices, households will have to reduce their consumption of all items, including electricity. The initial reduced consumption spending will be multiplied as it works its way through the rest of the economy, producing further rounds of value added and employment losses.

We use our short-run regional model to track the economic and employment effects from the $150 million rate increase to non-DSI customers. The model allows us to track the effects by sector of the economy. Table 1 provides current value added and job totals for the Northwest Economy – these serve as backdrop for computing relative impacts. The short-run model results themselves are shown in Tables 2 and 3.

Table 1 shows the baseline 2005 value added and employment, aggregated to 20 sectors. There is a total of $429 billion in value added for the Northwest region (modeled as Washington, Oregon, Idaho and western Montana).[15] The jobs total for the region is 6.93 million.

Table 2 shows how the $150 million per year increase in electricity prices would affect value added in the region, under our assumption of a perfectly inelastic demand for non-household electricity. The first set of columns shows the direct value added effect – the loss of value added directly due to owners' income loss in the commercial and industrial sectors, and the loss of payroll in the government sector. Since about half of the electricity is consumed by these sectors, the direct value added effect of $77.4 million is about half of the $150 million total rate increase. As this initial impact works its way through the economy, along with the direct household consumption impact of higher electricity prices, it spreads out more evenly across the sectors, especially those sectors that play a large role in household consumption, causing an additional $105.4 million loss of value added. The total impact, direct plus indirect value added, is $182.8 million per year.

Table 3 shows the impacts on jobs. The initial direct loss of 287 jobs is restricted to the government sector, reflecting our assumption that government responds to the electricity price increase by reducing payroll. The business sectors were assumed to keep payrolls unchanged, but absorb the price change in reduced owners' incomes. The indirect job loss as the impact

[14] Assuming that government responds by increasing taxes would produce nearly identical total employment and value added results, but with impacts shown for government in Tables 2 and 3 spread instead across the other non-government sectors of the model.

[15] Value added at the state level is sometimes referred to as "Gross State Product," or "GSP," and the values reported in Table 2 are generally consistent with published GSP estimates (e.g., www.bea.gov).

Table 1
Baseline 2005 Value Added and Employment
BPA Four-State Service Area

NAICS Code	Description	Value Added ($1,000)	% total	Jobs	% total
110000	Agriculture	$ 12,523,062	2.9%	288,937	4.2%
210000	Mining	$ 970,983	0.2%	13,594	0.2%
220000	Utilities	$ 6,170,056	1.4%	11,853	0.2%
230000	Construction	$ 22,114,500	5.2%	440,660	6.4%
3A0000	Manufacturing: nondurable goods	$ 16,279,910	3.8%	156,234	2.3%
3B0000	Manufacturing: durable goods	$ 42,748,611	9.9%	407,647	5.9%
420000	Trade	$ 54,552,500	12.7%	1,019,240	14.7%
480000	Transportation	$ 13,383,122	3.1%	219,511	3.2%
510000	Information	$ 30,185,826	7.0%	160,218	2.3%
520000	Finance and insurance	$ 26,993,770	6.3%	268,353	3.9%
530000	Real estate and leasing	$ 33,322,234	7.8%	273,325	3.9%
540000	Professional, Scientific, and Technical Services	$ 28,722,225	6.7%	429,010	6.2%
550000	Management of companies and enterprises	$ 6,861,370	1.6%	70,978	1.0%
560000	Administrative, support, waste mgt and remediation serv	$ 14,645,361	3.4%	362,637	5.2%
610000	Educational services	$ 2,901,989	0.7%	118,962	1.7%
620000	Health care and social assistance	$ 32,464,069	7.6%	675,477	9.7%
710000	Arts, entertainment and recreation	$ 4,160,522	1.0%	150,155	2.2%
720000	Accommodation and food services	$ 12,826,040	3.0%	455,011	6.6%
810000	Other services	$ 10,928,254	2.5%	364,701	5.3%
	Government	$ 56,571,074	13.2%	1,050,238	15.1%
	Total	$ 429,325,477	100.0%	6,936,738	100.0%

Table 2
Short-Run Value Added Impact of Electricity Rate Increase on Non-DSI Users
BPA Four-State Service Area

NAICS Code	Description	Direct ($1,000)	% total Direct	Indirect ($1,000)	% total indirect	Total ($1,000)	% total Total
110000	Agriculture	$ (2,715)	3.5%	$ (1,698)	1.6%	$ (4,413)	2.4%
210000	Mining	$ (640)	0.8%	$ (80)	0.1%	$ (721)	0.4%
220000	Utilities	$ (201)	0.3%	$ (1,980)	1.9%	$ (2,181)	1.2%
230000	Construction	$ (1,788)	2.3%	$ (1,356)	1.3%	$ (3,144)	1.7%
3A0000	Manufacturing: nondurable goods	$ (8,831)	11.4%	$ (4,275)	4.1%	$ (13,106)	7.2%
3B0000	Manufacturing: durable goods	$ (8,983)	11.6%	$ (2,619)	2.5%	$ (11,602)	6.3%
420000	Trade	$ (10,062)	13.0%	$ (21,142)	20.1%	$ (31,204)	17.1%
480000	Transportation	$ (1,334)	1.7%	$ (3,078)	2.9%	$ (4,412)	2.4%
510000	Information	$ (1,613)	2.1%	$ (5,135)	4.9%	$ (6,748)	3.7%
520000	Finance and insurance	$ (1,191)	1.5%	$ (8,656)	8.2%	$ (9,847)	5.4%
530000	Real estate and leasing	$ (10,266)	13.3%	$ (10,373)	9.8%	$ (20,639)	11.3%
540000	Professional, Scientific, and Technical Services	$ (1,629)	2.1%	$ (4,631)	4.4%	$ (6,260)	3.4%
550000	Management of companies and enterprises	$ (1,223)	1.6%	$ (1,544)	1.5%	$ (2,767)	1.5%
560000	Administrative, support, waste mgt and remediation serv	$ (1,641)	2.1%	$ (3,131)	3.0%	$ (4,772)	2.6%
610000	Educational services	$ (388)	0.5%	$ (836)	0.8%	$ (1,224)	0.7%
620000	Health care and social assistance	$ (3,425)	4.4%	$ (16,032)	15.2%	$ (19,457)	10.6%
710000	Arts, entertainment and recreation	$ (983)	1.3%	$ (1,734)	1.6%	$ (2,717)	1.5%
720000	Accommodation and food services	$ (4,175)	5.4%	$ (6,002)	5.7%	$ (10,177)	5.6%
810000	Other services	$ (1,649)	2.1%	$ (4,091)	3.9%	$ (5,740)	3.1%
	Government	$ (14,661)	18.9%	$ (7,020)	6.7%	$ (21,680)	11.9%
	Total	$ (77,397)	100.0%	$ (105,415)	100.0%	$(182,812)	100.0%

Table 3
Short-Run Jobs Impact of Electricity Rate Increase on Non-DSI Users
BPA Four-State Service Area

NAICS Code	Description	Direct	% total direct	Indirect	% total indirect	Total	% total Total
110000	Agriculture	-	0.0%	(47)	2.4%	(47)	2.1%
210000	Mining	-	0.0%	(1)	0.1%	(1)	0.1%
220000	Utilities	-	0.0%	(4)	0.2%	(4)	0.2%
230000	Construction	-	0.0%	(27)	1.4%	(27)	1.2%
3A0000	Manufacturing: nondurable goods	-	0.0%	(44)	2.2%	(44)	2.0%
3B0000	Manufacturing: durable goods	-	0.0%	(34)	1.8%	(34)	1.5%
420000	Trade	-	0.0%	(442)	22.7%	(442)	19.8%
480000	Transportation	-	0.0%	(53)	2.7%	(53)	2.4%
510000	Information	-	0.0%	(32)	1.6%	(32)	1.4%
520000	Finance and insurance	-	0.0%	(83)	4.2%	(83)	3.7%
530000	Real estate and leasing	-	0.0%	(93)	4.8%	(93)	4.2%
540000	Professional, Scientific, and Technical Services	-	0.0%	(74)	3.8%	(74)	3.3%
550000	Management of companies and enterprises	-	0.0%	(16)	0.8%	(16)	0.7%
560000	Administrative, support, waste mgt and remediation serv	-	0.0%	(83)	4.3%	(83)	3.7%
610000	Educational services	-	0.0%	(32)	1.6%	(32)	1.4%
620000	Health care and social assistance	-	0.0%	(330)	16.9%	(330)	14.8%
710000	Arts, entertainment and recreation	-	0.0%	(53)	2.7%	(53)	2.4%
720000	Accommodation and food services	-	0.0%	(216)	11.1%	(216)	9.7%
810000	Other services	-	0.0%	(142)	7.3%	(142)	6.4%
	Government	(287)	100.0%	(143)	7.4%	(430)	19.3%
	Total	(287)	100.0%	(1,948)	100.0%	(2,235)	100.0%

spreads out through the rest of the economy produces a further job loss of 1,948 jobs. The total short-run employment loss caused by the electricity price increase is estimated to be 2,235 jobs.

Our short-run model assumed that electricity consumers have no ability to adjust their electricity use in the time frame of a few months to a year. We know that is not really true – there are always some opportunities for both businesses and households to reduce power usage in response to higher prices. There are opportunities to turn down thermostats and turn out lights, in a few cases existing hardware may be amenable to fuel switching, but in the short-run these opportunities are limited relative to the longer-run, which we will discuss below. In the short-run, and for price increases of the magnitude used here, we would not expect to see major changes in output levels by businesses and manufacturing firms in the region, and we would expect few firms to close in the short-run because they can't pay the power costs.

Appendix Tables A2 and A3 include estimates of short-run elasticities from various studies, including the elasticity estimates embedded in the Energy Information Agency energy sector model. Clearly, the electricity demand estimates are quite diverse, depending on the assumptions, data and estimation methods used. The one-year short-run electricity demand elasticity estimates from Table A3 look quite plausible at -0.20 for residential and -0.10 for commercial electricity consumers.

Using the 7 to 8% electricity price increase to BPA non-DSI electricity consumers corresponding to a $150 million DSI rate subsidy would mean that customers would cut their electricity consumption by only 1 to 2%. This suggests that our short-run model assumption of perfectly inelastic demand response is probably not a bad assumption.

To the extent that some short-run demand response does occur, the effect can be both positive and negative. If electricity users are moved to adopt conservation measures because conservation is cheaper than paying the higher electricity price, then this reduces the regional effects of the price increase below our model estimates. If businesses are moved to make some cuts in output by higher power costs, this would cut profits, and increase the regional effects of the price increase above our model estimates. Our short-run model takes a middle route between these two offsetting paths.

The Long-Run Model

Over a longer time period, there will be opportunities for electricity users to adapt to higher prices. They may implement conservation; switch fuels, or implement other changes that reduce electricity use. In the extreme, businesses may be driven to drastically reduce production levels, suspend production, or even go out of business. Households face a similar range of options in the long-run. Comprehensively modeling all this would require information on the characteristics and adjustment alternatives facing each sector that are beyond the scope and the 2 ½ week time frame of this study. What we do is to build a model that allows for some of the flexible response we expect to occur. Our long-run model results are shown in tables 4 and 5.

Table 4
Long-Run Value Added Impact of Electricity Rate Increase on Non-DSI Users
BPA Four-State Service Area

NAICS Code	Description	Direct ($1,000)	% total direct	Indirect ($1,000)	% total indirect	Total ($1,000)	% total Total
110000	Agriculture	$ (968)	2.3%	$ (3,171)	2.7%	$ (4,139)	2.6%
210000	Mining	$ (333)	0.8%	$ (221)	0.2%	$ (554)	0.3%
220000	Utilities	$ (111)	0.3%	$ (2,360)	2.0%	$ (2,471)	1.5%
230000	Construction	$ (803)	1.9%	$ (2,758)	2.3%	$ (3,561)	2.2%
3A0000	Manufacturing: nondurable goods	$ (2,569)	6.2%	$ (4,978)	4.2%	$ (7,547)	4.7%
3B0000	Manufacturing: durable goods	$ (3,447)	8.3%	$ (4,253)	3.6%	$ (7,700)	4.8%
420000	Trade	$ (6,085)	14.7%	$ (21,521)	18.1%	$ (27,607)	17.3%
480000	Transportation	$ (725)	1.8%	$ (3,889)	3.3%	$ (4,614)	2.9%
510000	Information	$ (897)	2.2%	$ (5,819)	4.9%	$ (6,716)	4.2%
520000	Finance and insurance	$ (706)	1.7%	$ (8,713)	7.3%	$ (9,419)	5.9%
530000	Real estate and leasing	$ (7,126)	17.2%	$ (12,341)	10.4%	$ (19,468)	12.2%
540000	Professional, Scientific, and Technical Services	$ (1,091)	2.6%	$ (6,219)	5.2%	$ (7,311)	4.6%
550000	Management of companies and enterprises	$ (863)	2.1%	$ (2,217)	1.9%	$ (3,080)	1.9%
560000	Administrative, support, waste mgt and remediation serv	$ (923)	2.2%	$ (4,352)	3.7%	$ (5,276)	3.3%
610000	Educational services	$ (221)	0.5%	$ (774)	0.7%	$ (995)	0.6%
620000	Health care and social assistance	$ (2,052)	5.0%	$ (14,185)	12.0%	$ (16,237)	10.2%
710000	Arts, entertainment and recreation	$ (588)	1.4%	$ (1,628)	1.4%	$ (2,216)	1.4%
720000	Accommodation and food services	$ (2,229)	5.4%	$ (5,654)	4.8%	$ (7,883)	4.9%
810000	Other services	$ (915)	2.2%	$ (4,030)	3.4%	$ (4,945)	3.1%
	Government	$ (8,674)	21.0%	$ (9,556)	8.1%	$ (18,230)	11.4%
	Total	$ (41,327)	100.0%	$ (118,639)	100.0%	$(159,966)	100.0%

Table 5
Long-Run Jobs Impact of Electricity Rate Increase on Non-DSI Users
BPA Four-State Service Area

NAICS Code	Description	Direct	% total direct	Indirect	% total indirect	Total	% total Total
110000	Agriculture	(28)	3.9%	(74)	3.5%	(102)	3.6%
210000	Mining	(4)	0.6%	(3)	0.2%	(8)	0.3%
220000	Utilities	(0)	0.1%	(5)	0.2%	(5)	0.2%
230000	Construction	(16)	2.2%	(55)	2.6%	(71)	2.5%
3A0000	Manufacturing: nondurable goods	(20)	2.8%	(49)	2.3%	(70)	2.5%
3B0000	Manufacturing: durable goods	(35)	4.9%	(53)	2.5%	(88)	3.1%
420000	Trade	(134)	18.6%	(429)	20.4%	(563)	19.9%
480000	Transportation	(11)	1.6%	(67)	3.2%	(78)	2.8%
510000	Information	(6)	0.8%	(36)	1.7%	(42)	1.5%
520000	Finance and insurance	(8)	1.2%	(83)	3.9%	(91)	3.2%
530000	Real estate and leasing	(65)	9.0%	(109)	5.2%	(174)	6.2%
540000	Professional, Scientific, and Technical Services	(16)	2.2%	(99)	4.7%	(115)	4.1%
550000	Management of companies and enterprises	(9)	1.2%	(23)	1.1%	(32)	1.1%
560000	Administrative, support, waste mgt and remediation serv	(13)	1.8%	(114)	5.4%	(127)	4.5%
610000	Educational services	(9)	1.3%	(30)	1.4%	(39)	1.4%
620000	Health care and social assistance	(51)	7.1%	(293)	13.9%	(344)	12.2%
710000	Arts, entertainment and recreation	(19)	2.7%	(51)	2.4%	(70)	2.5%
720000	Accommodation and food services	(79)	10.9%	(202)	9.6%	(281)	10.0%
810000	Other services	(27)	3.7%	(134)	6.4%	(161)	5.7%
	Government	(170)	23.5%	(195)	9.3%	(365)	12.9%
	Total	(720)	100.0%	(2,103)	100.0%	(2,823)	100.0%

Our model assumes a unitary demand elasticity for the products produced in the region (that is, if the price of these products increases, the quantity demanded will fall by the same percentage, leaving total revenues unchanged). We also keep the usual assumption of input-output analysis that physical production inputs change in constant proportion. Now, value added in the production sectors will fall, both because businesses and industries pay more for electricity, and because they will be producing less output. Again, the resulting losses of value added in the production sectors and the real income effects of higher prices for electricity to the household sectors will be translated into impacts on employment and income by sector.

Our long-run model results in tables 4 and 5 are actually not that much different from our short-run model results shown in tables 2 and 3. The comparison is summarized in Table 6. The total impacts on value added and the total impacts on jobs are quite similarly distributed across the sectors. The $160.0 million total annual impact on value added is somewhat less than the $182.8 million annual impact estimated by the short-run model. The 2,823 long-run jobs impact is somewhat more than the 2,235 jobs found by the short-run model.

Table 6

Short-Run and Long-Run Employment and Value Added Effects of Higher Electric Rates to Non-DSI Electricity Users

	Direct	Indirect	Total
Short-Run			
Value Added ($ million per year)	-77.4	-105.4	-182.8
Employment (# of jobs)	-287	-1,948	-2,235
Long-Run			
Value Added ($ million per year)	-41.3	-118.6	-160.0
Employment (# of jobs)	-720	-2,103	-2,823

There is no a priori reason why the long run economic impact of an electricity price increase should be higher or lower than the economic impact in the short run. The long-run allows time for electricity consumers to take steps to adjust to the higher prices in ways that would reduce their economic impact. On the other hand, the long run may give some marginal users time to face the reality that higher electricity prices have made them no longer competitive in the marketplace, and to perhaps move from the region or exit from production, which would increase the economic impact.

However it is instructive to compare short-run Tables 2 and 3 and long-run Tables 4 and 5. In particular, the short-run value-added impact ($182.8 million) is larger than the long-run value-added impact ($160 million). In contrast, the impacts on jobs are just the opposite. The short-run model estimates the employment loss as 2,235, while the long-run model estimate is higher at 2,823. Recall that in the short-run higher electricity prices are covered by reduced owners' incomes, while holding direct output levels constant: in the short-run, a relatively large portion of the overall value added impact is reduced owners' incomes, with no corresponding effect on direct employment. In the long-run, owners move to restore profit margins by raising output prices: the response is a reduction in the level of output, with a loss of employee wages. The long-run thus results in a greater job loss than the short-run because it allows for this output change. At the same time, value added impacts decline because profit margins are restored: with time to adjust, a considerable portion of the burden of the electricity price increase is shifted from business owners to employees.

In the long-run, consumers have many options for responding to and adjusting to higher electricity prices. Tables A-2 and A-3 illustrate the wide range of estimates of long-run elasticity of electricity demand with respect to electricity price. The elasticity estimates range from about -0.5 to -2.0 or even more. This means that a 1% increase in electricity price would cause electricity demand to drop by somewhere between 0.5% and 2.0%. This kind of response would be expected from both commercial and household electricity users. Table A-3 suggests that commercial sectors for which electricity is a “core end use” (e.g. computer server farms, pulp and paper mills, or other industries which use electricity for process heat) would be even more responsive to price than other electricity users, especially if they respond by exiting from production or from the region.

Contrary to the standard input-output model assumption, that production inputs are used in fixed proportions, which we adhered to in our model, electricity users actually have many opportunities to change the input mix they use. Faced with higher electricity prices, electricity users may substitute capital investment for electricity – we normally call this “conservation”. Businesses may invest in new energy efficient machinery, better insulation, and energy saving process control devices. Households may invest in new energy efficient appliances, compact fluorescent lighting, and automated lighting and heating control systems, or just do a little better in turning out lights in unoccupied rooms. If the costs of these conservation measures are exceeded by the savings in electricity costs then this investment reduces the total economic impact of the electricity price increase.

The flexibility to change input mix goes well beyond just conservation. Electricity is one of several alternative energy sources. Fuel substitution – substituting one energy source for another -- is often a possible response to price changes. Both commercial and residential space heating can be powered by electricity, natural gas, or fuel oil, whichever is cheaper. Some industries require process heat, which could be supplied by natural gas, fuel oil or electricity, whichever is cheaper. Of course the changeovers can be expensive, so this is usually a long-run proposition. However, if the costs of these fuel substitution measures are exceeded by the savings in electricity costs then this reduces the total economic impact of the electricity price increase.

In some cases there may be businesses which use lots of electricity but find little scope for electricity conservation or fuel substitution. In these instances higher fuel prices simply translate into higher costs and reduced competitiveness of that business. Such businesses may be able to survive for a time paying higher electricity costs, living on the depreciation of the business assets, and surviving on reduced owner’s income. However, that is not a viable long-run strategy. In the long-run such a business will face the reality that their capital has depreciated and replacing it with new investment is not justified. In the long-run the owners of such businesses will find better things to do than survive on reduced owners’ incomes. One example of such an industry might be electric pump irrigation. Irrigators who pump from very deep wells, or lift water to fields a considerable height above a river may have little they can do to mitigate higher prices for pumping electricity. Another example might be a pulp and paper mill that uses large amounts of electricity for mechanical power. In the long-run businesses such as these can be expected to cut back production, leave the region, or go out of business if electricity prices increase above some threshold. To the extent that this happens, the economic impact of higher electricity prices on jobs and value added will be higher than estimated by our long-run model.

We have given reasons why the adjustment opportunities actually available to electricity users might result in economic impacts somewhat above or below what we estimated with our somewhat rigid long-run model, and why the long run impacts might be less than or more than the short-run impacts. We view our models as taking an intermediate road between these possibilities, unless the subsidy and the consequent rate increase is at the upper end of the possible range, in which case our model may underestimate the value added and jobs impact.

Our bottom line is that we believe that the economic impact of a $150 million rate subsidy for the DSIs would be a decrease in the range of at least $160 to $180 million in annual regional value added and a decrease in the range of at least 2,200 to 2,800 jobs throughout the regional economy.

What if the subsidy is less than $150 million?

We indicated earlier that the $150 million rate subsidy was a very uncertain number. The $150 million is perhaps close to an upper bound, and the actual number might be $100 million -- or $50 million.

To actually empirically estimate the impacts of these alternative rate subsidy levels would require some quite sophisticated modeling (similar to what the Council did for the aluminum industry in their 5th Power Plan) which was beyond the data we had and the time we had available to do this study.

However, we can say what kind of response pattern we would expect. We would expect the severity of the economic impacts to escalate with the increased size of the subsidy, and this effect will be greater for the more electricity intensive sectors of the economy. For small electricity rate increases, users face a range of adjustment possibilities, such as conservation and fuel switching, which can mitigate the economic impacts. For larger price increases the easy adjustment opportunities will be typically exhausted, and the remaining ones more expensive.

For the electricity intensive industries with few opportunities to adjust to higher prices, when prices increase above some threshold the likely response is to go out of business or go bankrupt. Thus at high subsidy levels to the DSIs, and the resulting high rate increases to all other users, loss of employment and loss of value added may be even higher than estimated by our model.

Of course, our short-run and long-run models assumed that inputs were used in fixed proportions and did not actually allow for all these adjustment possibilities. Thus in a formal sense, if one were to use our models to estimate the impacts of smaller subsidies, the impacts would be proportional as shown in table 7.

It is still useful to keep in mind that in the real world these impacts would escalate with the larger subsidy, and that at higher subsidy and rate increase levels our model may underestimate the impacts.

Table 7

Employment and Value Added Effects of Higher Electric Rates to Non-DSI Electricity Users, at Various Subsidy Sizes

	Size of Subsidy to DSIs		
	$50 million	$100 million	$150 million
Short-Run			
Value Added ($ million)	-$60.9	-$121.9	-$182.8
Employment (# of jobs)	-745	-1,490	-2,235
Long-Run			
Value Added ($ million)	-$53.3	-$106.6	-$160.0
Employment (# of jobs)	-941	-1,882	-2,823

Conclusions

Our conclusion from our modeling is that if a DSI rate subsidy of $150 million is passed back to all non-DSI customers in the form of higher electric rates, the result would be a value added loss of $160 million to $180 million per year and an employment loss of at least 2,200 to 2,800 jobs. This potential significant loss of employment and value added from higher electricity prices to non-DSI consumers needs to be seriously weighed by policy-makers before any decision is made to provide rate subsidies to the DSIs.

One further conclusion should be noted. Our model did not disaggregate the effects of the price changes by region. However, if the model had allowed this level of detail, it would have shown that the effects of the DSI rate subsidy differ considerably between different parts of the PNW. The price increases were assumed to be borne by non-DSI electricity users all across the BPA service area. However, the job and value added benefits from the aluminum industry would be concentrated in the sub-regions near the smelters. The large parts of the BPA service area that are distant from smelters would bear significant costs from a DSI rate subsidy, but reap few benefits.

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Appendix A: Data

Table A1: Basic Data for Public Power Council Study

	Item	Source	Year	Units	Total	Residential	Commercial	Industrial Non-DSI	DSI	Irrigation	Other
1	Total Regional Electricity Demand	NPCC 5th Power Plan	2006 2011	average MW average MW	19,621 20,917	7,340 7,789	5,509 5,835	4997 5498	958 958	631 644	186 193

	Item	Source	Year	Units	Total	DSI	Public Entities	Federal & Other	Investor Owned	Exports
2	Total Regional Firm Energy Load	BPA 2004 PNW Loads & Resources Study	2006	average MW	21,706	296	8,531	457	11,025	1,397

	Item	Source	Year	Units	Total	DSI	Public Owned	USBR	Federal Agency
3	BPA Contract Load Obligations, PNW Region	BPA 2004 PNW Loads & Resources Study	2006 2011	average MW average MW	7,019 7,450	271 0	6,481 7,155	149 149	118 146

	Item	Source	Year	Units	Commercial	Residential	DSI Firm	Non DSI Firm	Irrigation	Other	Total Firm Sales	Total Non-DSI Sales
4	Total Annual Sales to End-Use Customers (Not Weather Adjusted)											
	Total	NPCC Staff	2004	average MW	5,547	6,685	311	3654	713	178	17,088	16,777
	Public Customer Pool	NPCC Staff	2004	average MW	2,169	2,918	311	1819	369	140	7,726	7,415
	Public as % of Total	Computed	2004	percent	39.1%	43.6%	100.0%	49.8%	51.8%	78.7%	45.2%	44.2%

	Item	Source	Year	Units	Total	DSI	Non-DSI	Public Owned	Investor owned
5	BPA Sales Within the PNW Region	BPA 2005 Annual Report	2005	$ thousands	2,190,028	82,454	2,107,574	1,717,063	390,511

	Item	Source	Residential	Commercial	Irrigation
6	Long-Run Elasticity for Electricity Demand	NPCC Staff	-0.4	-0.53	-0.24

	Item	Source	Period	Units	Shaped	Flat
7	BPA Priority Firm Wholesale Rate (undelivered)	BPA	4/1/06 to 9/30/06	cents/kWh	2.91	2.58

Table A2. Summary of Ranges of Residential and Commercial Elasticities from Dahl (1993)

Survey Source	Fuel	Data Type	Model Class	Short Run	Intermedia te Run	Long Run
Residential Sector						
Taylor (1977)	Electricity	Grouped	Grouped	-0.07 to -0.61	-0.34 to -1.00	-0.01 to -1.66
	Natural Gas	Aggregate		0.00 to -0.16		0.00 to -3.00
Bohi (1981)	Electricity	Aggregate	Static	-0.00 to -0.45		-0.40 to -1.53
	Electricity	Aggregate	Dynamic	0.49		-0.44 to -1.09
	Electricity	Aggregate	Structural	-0.16		0.00 to -1.20
	Electricity	Aggregate	Other	-0.10 to -0.54		-0.72 to -2.10
	Electricity	Household	Dynamic	-0.16		-0.45
	Electricity	Household	Static	-0.14		-0.7
	Electricity	Household	Structural	-0.25		-0.66
	Natural Gas	Aggregate	Static			-1.54 to -2.42
	Natural Gas	Aggregate	Dynamic	-0.15 to -0.50		-0.40 to -1.02
	Natural Gas	Aggregate	Structural	-0.50		-2.00
	Natural Gas	Household	Dynamic	-0.20		-0.57
	Natural Gas	Household	Static			-0.17 to -0.45
(1984)	Electricity	Aggregate	Static		0.00 to -1.57	-0.10 to -0.52
	Electricity	Aggregate	Dynamic	0.00 to -0.55		-0.26 to -2.50
	Electricity	Household	Structural	-0.20 to -0.76		
	Electricity	Household	Static		-0.55 to -0.71	-0.05 to -0.71
	Electricity	Household	Structural	0.67		-1.40 to -1.51
	Natural Gas	Aggregate	Dynamic	-0.23 to -0.35		-2.73 to -3.44
	Natural Gas	Aggregate	Dynamic	-0.03 to -0.05		0.55
	Natural Gas	Household	Static			0.60
Surveys	Fuel Oil	Grouped	Grouped	0.00 to -0.70		0.00 to -1.50
Dahl (1993) New Studies	Electricity	Aggregate	Grouped	+0.57 to -0.60	-0.11 to -1.11	+0.77 to -2.20
	Electricity	Household	Grouped	-0.02 to -0.97	-0.05 to -0.97	-0.30 to -1.40
	Natural Gas	Aggregate	Grouped	0.35	1.06 to -2.41	1.56 to -3.44
	Natural Gas	Household	Grouped	0.00	-0.00 to -1.00	-1.03 to -1.43
	Fuel Oil	Aggregate	Grouped	-0.10 to -0.53	-0.77 to -1.22	-1.05 to -3.5
	Fuel Oil	Household	Grouped	-0.10 to -0.13	-1.03 to -1.56	-0.62 to -0.67
Commercial Sector						
Taylor (1977)	Electricity	Aggregate	Grouped	-0.24 to -0.54		-0.05 to -1.22
	Natural Gas	Aggregate		-0.30		-1.45
Bohi (1981)	Electricity	Aggregate	Dynamic	-0.17 to -1.10		-0.56 to -1.60
	Natural Gas	Disaggregate	Static			-1.04
(1984)	Electricity	Disaggregate	Grouped		0.00 to -4.56	0.00 to -1.05
	Natural Gas	Aggregate	Dynamic	0.00 to -0.37		0.00 to -2.27
Surveys	Fuel Oil	Grouped	Grouped	-0.30 to -0.61		-0.55 to -0.70
Dahl (1993) New Studies	Electricity	Aggregate	Grouped	0.00 to -0.02	-0.59 to -0.90	0.36 to -4.74
	Natural Gas	Aggregate	Grouped	-0.16 to -0.37	1.32 to -2.60	0.06 to -2.27
	Fuel Oil	Aggregate	Grouped	-0.07 to -0.19	-0.30	-0.40 to -3.50

Source: Quoted in Steven H. Wade, Price Responsiveness in the NEMS Building Sector Model, Report#:EIA/DOE-0607(99)
http://www.eia.doe.gov/oiaf/issues/building_sector.html

Table A3:. Summary of Price Responses in the NEMS *AEO2003* and *AEO99*
Residential and Commercial Buildings Models

Sector and Fuel	NEMS Model Year	Short-Run Own-Price Elasticity			Long-Run Own-Price and Cross-Price Elasticity		
		1-Year	2-Year	3-Year	Electricity	Natural Gas	Distillate Fuel
Residential							
Electricity	*AEO2003*	-0.20	-0.29	**-0.34**	**-0.49**	0.01	0.00
	AEO99	-0.23			-0.31	0.03	0.00
Natural Gas	*AEO2003*	-0.14	-0.24	**-0.30**	0.13	**-0.41**	0.02
	AEO99	-0.26			0.08	-0.43	0.02
Distillate Fuel	*AEO2003*	-0.15	-0.27	**-0.34**	0.01	0.05	**-0.60**
	AEO99	-0.28			0.05	0.15	-0.53
Commercial							
Electricity	*AEO2003*	-0.10	-0.17	**-0.20**	**-0.45**	0.01	0.00
	AEO99	-0.23			-0.24	0.00	0.00
Natural Gas	*AEO2003*	-0.14	-0.24	**-0.29**	0.86	**-0.40**	0.01
	AEO99	-0.26			0.00	-0.34	0.03
Distillate Fuel	*AEO2003*	-0.13	-0.23	**-0.28**	0.08	0.75	**-0.39**
	AEO99	-0.47			0.00	0.49	-0.87
Commercial Electricity by End Use							
Core End Uses	*AEO2003*	-0.17	-0.29	**-0.36**	**-0.88**	—	—
	AEO99	-0.24			-0.31	—	—
Other End Uses	*AEO2003*	-0.03	-0.05	**-0.06**	**-0.24**	—	—
	AEO99	-0.24			-0.20	[illegible]	[illegible]

Source: Steven H. Wade, Price Responsiveness in the AEO2003 NEMS Residential and Commercial Buildings Sector Models, Energy Information Agency, March 2005
http://www.eia.doe.gov/oiaf/analysispaper/elasticity/

Appendix B
Comments on the EMSI Input-Output Model

We completed the impact analysis reported above using the Economic Modeling Specialists, Inc. (EMSI) EI Model. The EMSI EI Model is constructed using the U.S. National IO Model using standard non-survey IO modeling techniques. For more information on the EMSI EI Model see: www.economicmodeling.com.

Short-Run

Following standard practice, we define the "short-run" as the period over which little adjustment to higher electricity prices are possible: there is no direct change in industry outputs, industry inputs or the relative proportion of total income spent on the various goods that make up the household consumption bundle. The $150 million in increased electricity costs are entirely born by business owners in the case of private industry, by reductions in employee wages in the case of government, and by a reduction in the real purchasing power of households. We display the short-run "direct impact" as the direct loss of business owner and government sector incomes. Indirect impacts are estimated by applying the effective loss of household income, i.e., the loss of owners' and government worker incomes, and the net real reduction in household spending, to the household sector of the IO model.

Long-Run

Generally speaking, IO models do not allow for changes in the relative use of production inputs: e.g., the adoption of conservation measures, or the substitution of natural gas or other energy sources for electricity. Within the context of fixed input proportion we are, however, able to model the effect of higher electricity prices on overall industry outputs, and speculate on the magnitude of neglected substitution effects.

For our long-run analysis, we assume businesses owners move to recapture lost profit margins by raising prices, and that government reduces overall service levels. We assume the elasticity of demand for final products are unitary, so the effect of shifting electricity price increases to final output prices is an exactly equal reduction in business output. We enter these reductions into the model as changes in final demand.