BP Cherry Point Cogen
DEIS Comment - 19

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Allen Fiksdal
EFSEC Manager
P.O. Box 43172
Olympia, WA 98504

October 30, 2003

Dear Mr. Fiksdal,

Please find enclosed my comments on the BP Cherry Point Cogeneration DEIS.
I have also sent them to you electronically.

Thank you,

Trina Blake
NW Energy Coalition

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TO: Members, WA State Energy Facility Site Evaluation Council

FROM: Trina Blake, NW Energy Coalition
DATE: October 30, 2003
RE: BP Cherry Point Cogeneration Project DEIS

Thank you for the opportunity to comment on the BP Cherry Point Cogeneration Project DEIS, specifically on the proposed CO2 mitigation proposal.

We appreciate the Council addressing the issue of Greenhouse Gas emissions, and including a section on its cumulative impacts. However, while the DEIS says there is "still uncertainty" about the magnitude of future impacts of global warming (section 3.2.5), EFSEC members are already clearly on record acknowledging that the risks of waiting to act on global warming are too great. The first impacts are already being felt, from reduction in the snowpack to forest infestations, and even the low-end of predicted changes will have dire consequences. The Council has heard from scientists such as Dr. Richard Gammon and the University of Washington on the impacts to Washington State from global warming. Scientists quoted in the DEIS itself predict that global warming will impact the Pacific Northwest in the next 50 years by reducing snow pack, increasing precipitation in winter and decreasing precipitation in summer, all of these leading to adverse impacts on irrigated agriculture, forests, and salmon. The region's traditional base load power source, hydroelectric dams, are also threatened by summer flows 20-30% beneath current levels, with significant impacts on summer power production and rates. These impacts to Washington, if CO2 is not reduced will be devastating to the economy and the environment. Obviously, any new plant permitted would increase emissions.

The DEIS does contain some very good proposals. First, decommissioning of the old boilers is a great idea and should be made an absolute requirement of building the proposed facility. The boilers are polluting and unnecessary, and should be permanently removed. 1

Second, fully mitigating CO2 emissions from the proposed plant through BP's corporate greenhouse gas objective is an excellent plan. However, we understand TransCanada already plans to purchase the facility permit. Because BP is committed to reducing CO2 around the globe, the company should make full mitigation a condition of sale, perhaps even working with TransCanada to mitigate CO2 emissions. Assuming that this is not made a condition of sale, we now must address the alternative proposal, which is wholly inadequate, as it is not based on sound scientific or economic principles. 2

<u>Plan if the Plant is sold:</u>

<u>Capacity Factor</u>

This plan has a capacity factor assumed to be 85%. This might be acceptable if the plant's CO2 emissions were mitigated fully, but to allow a reduced capacity without full mitigation invites gaming. Oregon requires, and this plan should too, a capacity factor to be assumed at 100%. 3

<u>Emissions Limit</u>

In calculating the emissions to be mitigated, the current Oregon standard (suggested in the DEIS), which requires emissions exceeding 0.675 lb/kwh (River Road technology minus 17%) to be mitigated, no longer reflects the most efficient combined cycle combustion turbine technology available. The Council should require mitigation of emissions from the 4 baseline of the most efficient combined cycle combustion turbine operating at the time the final mitigation plan is approved. Based on our research, the most efficient combustion turbine technology currently available is the Siemens Westinghouse W501G turbine at 0.764 lbs CO_2/kWh. Applying the 17% reduction in the Oregon standard to this technology would yield a baseline of 0.634 lbs CO_2/kWh. But we are not recommending 17%. We would like to see full mitigation as proposed under BP ownership. We have also recommended to the Council a very economical standard of 0.458 lb CO_2/kWh, based on 40 percent below emissions from a state-of-the-art combined cycle gas-fired plant (See attachment A, the Tellus economic study on CO_2 mitigation). Governor Locke has called for a minimum of 20% of total emissions to be mitigated. 4 cont.

Payment

The suggested price, $0.85/ton, reflects the outdated and insufficient Oregon standard, in practice leaving 95% of CO_2 emissions unmitigated. The time frame for payments (annual over 30 years) would effectively gut any ability of this proposal to mitigate CO_2. In order to actually mitigate a ton of CO_2 emissions, the funding must be at a level near the market cost of mitigating that ton (between $2 and $5/ton based on Seattle City Light and Climate Trust figures). This could be achieved by setting the mitigation price at the current market price (2-5 dollars/ton CO_2) and indexing the price to the CO_2 offset market for any payments that occur in the future. The DEIS proposal also endorses annual payments spread over 30 years. Annual payments would unnecessarily constrain the types of CO_2 mitigation projects that could be purchased, and thereby increase costs. The project owner should plan on providing the total amount of payment within the first five years of facility operation. That is a modification on the Oregon standard, which requires a single up front payment at the beginning of facility operation. Providing the mitigation payment up front allows the entity acquiring the offsets to purchase larger, more cost-effective mitigation projects. It also reduces any uncertainties associated with adjusting the price per ton to a market index over time. If however, EFSEC approves an annualized requirement, that requirement must apply for the entire life of the project and be indexed to market prices. In addition, the 30-year facility life proposed is based on Oregon law. Oregon uses a shortened estimated life span as an incentive to follow their monetary path and pay up front. If full upfront payment is not required; the mitigation should be required for the actual life of the proposed facility. 5

This proposal also omits administrative costs. If the proposal includes a monetary compliance path, it must explicitly include additional administrative costs of the entity managing the offset projects. As EFSEC found in its order on the Sumas Energy 2 facility, it had the legal power to impose administrative costs, and believes, in general, that it is appropriate to require the certificate holder to help pay such costs. Administrative costs are an essential part of ensuring that mitigation is accomplished in a credible manner that will count toward future regulatory requirements. The Council should recognize the true cost of the administration. In the Satsop agreement approved by Council members, administrative fees were set at 7.5%. Undercutting the real cost would further reduce the effectiveness of the mitigation, as money from the cost per ton would have to be used in order to secure projects 6

Finally, the plan must require the applicant to choose (if both are offered) between a monetary path (money paid to a third party) and mitigation obtained by the owner of the facility. To allow both invites gaming and further undercuts real mitigation. Any mitigation obtained directly by the owner of the proposed facility should be acquired at cost. To allow direct mitigation at the same price as the monetary path further reduces the tons of CO_2 mitigated 7

The extraordinary threats to Washington's environment and economy associated with greenhouse gas emissions are well documented. EFSEC's final EIS decision should strike an appropriate balance between the costs and benefits of these facilities. A strong mitigation requirement now will significantly reduce environmental costs AND financial costs. Utility and financial analysts universally project that the value of CO_2 offsets and allowances will increase as binding constraints on greenhouse gases are adopted worldwide. Relatively inexpensive mitigation now is low-cost insurance against compliance costs that will rise as the right to emit CO_2 becomes an increasingly scarce and valuable commodity. We urge the Council to ensure that the CO_2 mitigation plan achieves a meaningful environmental goal and substantially reduces exposure to future costs associated with purchasing CO_2 allowances or credits. Again, thank you for this opportunity to comment, and for your commitment to reduce the environmental and economic costs associated with CO_2 emissions from this proposed facility. 8

Attachment "A"

An Economic and Financial Analysis of the Proposed CO2 Rule
Comments for the Energy Facility Siting Council[1]

Michael Lazarus, Senior Scientist, Tellus Institute[2]

July 31, 2003

Introduction
I appreciate the opportunity to comment on EFSEC's proposed CO2 rule. I am a Senior Scientist with Tellus Institute, where I've done energy and environmental analysis for nearly 20 years, climate policy studies for the past 12 years, and analysis of emissions trading and offsets for the past 6 years. I work with a wide variety of clients, funders, and collaborators, including from the World Bank, USEPA, state and local agencies, foundations, project developers and brokers, and the non-governmental organizations. Among other current duties, I presently sit on Methodology Panel of the Clean Development Mechanism of the Kyoto Protocol, which is charged with developing draft guidelines and procedural recommendations for what could be considered the world's largest offset market.

Basic Approach
In this instance, I've been asked by the Northwest Energy Coalition to examine the economic and financial impacts of various possible formulations of a CO2 standard. This summary provides an overview of key assumptions and results. The analytical methodology, which combines straight-forward cash flow analysis, busbar electricity cost calculations, and cost-benefit comparisons, is detailed in an accompanying spreadsheet.

I have used widely available data and assumptions – drawn largely from Northwest Power Planning Council (NPPC) documents, supplemented by published studies by the US Department of Energy (USDOE), the Massachusetts Institute of Technology (MIT), and personal experience and contacts in the offsets market -- to calculate cost impacts across a range of proposed offset requirements (17%, 40%, and 100% of plant emissions) and mitigation prices, from the Oregon standard price[3] to the "all-in" cost of acquiring offsets (market price plus administrative and production costs).[4] For simplicity, I only consider one payment option – upfront payment spread over 5 years, financed by the developer – for a hypothetical 540 MW natural gas fired combined-cycle plant, placed in service in 2005.[5] I then look at the overall impact on the costs of

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[1] Draft results were presented at EFSEC's July 17 public meeting in Olympia. Updated results are presented here reflect further refinements of the analysis.
[2] Contact information: 119 First Ave S, Suite 400, Seattle, WA 98104, (206) 985-8124, mlaz@tellus.org.
[3] The Oregon CO2 standard price has been at \$0.85/tCO2 for a several years, after increasing 50% from its original \$0.57/tCO2 level. The price is allowed to increase by up to 50% every 2 years to more closely match prices actual paid for offsets. I assume that by 2005, the OR price will be at 0.85 x 1.5 or \$1.28/tCO2, given that offset prices are already well above this level, and that the price rises at 10%/year afterwards, roughly matching historical trends. (All "t" represent short, rather than metric, tons except where indicated)
[4] I have used rather conservative estimates of the market costs of offsets: \$2.50/tCO2 in 2003 rising to \$5/tCO2 by 2010, plus \$0.5/tCO2 for production/administrative services (contracting, M&V, baselines, etc.) that are essential for providing quality offsets. See World Bank's State and Trends in the Carbon Market reports at www.prototypecarbonfund.org
[5] Key assumptions were derived from the "Default assumptions from: NW Power Planning Council, New Resource Characterization for the Fifth Power Plan, Natural Gas Combined-cycle Gas Turbine Power Plants", August 27,

producing electricity from this power plant, and how a change in overall costs would be reflected in consumer rates, assuming such changes were passed through in rates rather than absorbed by developers as lower (or higher) profits. This assumption may overestimate rate impacts considerably.

Avoiding future compliance costs
It is important to recognize that investing in emissions reductions now hedges not only against future climate impacts, but also against the financial liabilities of major new assets responsible for significant emissions. These prospective liabilities are increasing in prominence and magnitude, as reflected in greater corporate and shareholder concern for greenhouse gas (GHG)-intensive activities, and in rising regional and national legislative activity.[6] While the timing and stringency of mandatory controls economy-wide or electric-sector-wide CO_2 emissions is highly uncertain, it appears increasingly likely that such controls are coming, and that early action could translate into a competitive advantage. Indeed, they are almost universally regarded as necessary if we are to take the challenge of climate stabilization seriously.

Once mandatory CO_2 emissions limits are adopted at the regional or national level, and power plants were required to hold emissions allowances for CO_2 much as they must today for sulfur oxides, power plants could face very significant costs of compliance. If exchangeable with emissions allowances in the future, CO_2 emissions offsets acquired under an EFSEC CO_2 rule could provide an important economic asset.[7]

Consider, for instance, currently pending national legislation aimed at curbing GHG emissions, the Climate Stewardship Act (Senate Bill S.139), also referred to as the McCain-Lieberman bill. It creates a market-based cap-and-trade program to reduce emissions, patterned after the acid rain program of the 1990 Clean Air Act. As with the acid rain program, major emissions sources (including electricity generators) would be required to hold an allowance (or permit) for every ton of CO_2-equivalent emissions. The Climate Stewardship Act sets a target of reducing national GHG emissions to 2000 levels by 2010, and to 1990 levels by 2016, targets far less ambitious than the Kyoto Protocol (7% below 1990 levels by 2008-2012). Emissions sources would be allowed to use "off-system credits", i.e. offsets, from non-regulated US sectors (including smaller sources, forestry and agriculture) and a wide range of international sources to meet their emissions targets, similar to what might be purchased under an EFSEC CO_2 rule.[8] While the Climate Stewardship Act is viewed as having little chance under the current Congress, it is viewed as a setting the template for future legislation.[9]

2002 Draft. These include an all-inclusive capital cost of $617/kW, heat rate of 7030 btu/kWh, and availability of 92%, which I simplified to a 90% capacity factor. Remaining assumptions are documented in the accompanying spreadsheet.

[6] See, for example, Rabe, B. 2002. *Greenhouse & Statehouse: The Evolving State Government Role in Climate Change*, and Margolick, M. and Russell, D., 2001. *Corporate Greenhouse Gas Reduction Targets*, Prepared for the Pew Center on Global Climate Change, November. www.pewclimate.org

[7] If CO_2 permits were grandfathered to existing sources, as was done with SO_2, compliance costs would be far lower, but the value of offsets would be the same, since they would enable excess permits to be sold as a source of revenue.

[8] Note that "in-system" offsets, e.g. project activities that reduce emissions by major fuel users, could still maintain future value, depending on how the terms of the offsets contracts were negotiated.

[9] Pizer, W., Kopp, R, 2003. *Summary and Analysis of McCain-Lieberman – "Climate Stewardship Act of 2003"* Resources for the Future, January 28. www.rff.org/McCain_Lieberman_Summary.pdf

Two key elements of this legislation are particularly relevant for EFSEC deliberations:

- **Scope for offsets.** While the rules on allowable credits are not specifically defined in the legislation, it is reasonable to assume that credible and verifiable offsets – as might be purchased under the EFSEC rule – would be deemed eligible. It is unclear whether emissions reductions occurring prior to 2010 would count, but the legislation is generous with respect to crediting what is considered early action prior to this date.[10] Experience from other cap-and-trade systems (e.g. Kyoto Protocol and acid rain) suggests that offset-like instruments are likely to be recognized in CO2 emissions legislation, as it adds flexibility, lower compliance costs, and motivates action in non-capped sectors. Parallel efforts, such as the California Climate Registry and GHG Protocol, are also presently underway to help ensure that early actors, such as power plant developers buying offsets, will be rewarded under future regulation.
- **Projected allowance costs.** Several recent modeling studies have sought to estimate the future cost of allowances under the Climate Stewardship Act. Recent modeling runs by the US DOE suggest that allowances, under a scenario with considerable use of offsets, would cost $20/tCO2 in 2010 and $44/tCO2 in 2020.[11] MIT modeling studies suggest allowance costs ranging from $15/tCO2 up to $25/tCO2, under a similar scenario. While these estimates may be somewhat high for technical reasons[12], it is instructive to note that these values are nearly ten times the offsets today and projected over the rest of the decade ($3.00-$5.50/tCO2).

Overall there are four key factors that will determine the extent to which offsets purchased under the EFSEC CO2 rule might provide a future economic benefit

a) the **likelihood** of future CO2 emission caps
b) the **cost of allowances,** which is a function of how stringent this cap would be.
c) the **transferability** or validity of CO2 offsets purchased under the EFSEC rule under a future cap-and-trade system.
d) the **timing** of these caps, which will affect the risk and time value of the benefits

The risk management benefit provided by offsets is the product of these four factors.

A Scenario Approach to Assessing Risks

Scenario analysis provides a useful way to examine a situation with such speculative factors. In the section below, I will present three alternative scenarios. The first represents a situation where there is no tangible risk management benefit. CO2 emissions are either not to be capped during the operating lifetime of the power plant (e.g. by 2034), or if they are, offsets purchased

[10] In any case, a threshold date (e.g. 2010) would likely not pose a major concern, since offset contracts would likely generate emission reductions across the full 30 year life of the power plant, e.g. 2005-2034 in the case of a plant in service in 2005. It is likely that, at most, only a small fraction of offset-based emission reductions might be ineligible.

[11] These estimates are drawn from the Pew Center's review of S. 139 studies, available at http://www.pewclimate.org/policy/EIAanalysis.cfm, where they are presented in metric tons.

[12] See Pew Center report noted above and Bailie, A., Bernow, S., and Lazarus, M., (2003) *Analysis of the Climate Stewardship Act,* Tellus Institute, Boston.

today would have no value in this system.[13] The second scenario represents a situation where legislation akin to the Climate Stewardship Act is adopted, with emissions caps starting in 2010, average allowance costs of $25/tCO2 (based roughly on the above DOE and MIT analyses), and full scope for including post-2009 offsets[14] purchased under an EFSEC rule. The third is an intermediate scenario, where doubts about likelihood of emissions caps, the future validity of offsets, and projected allowance costs, combine to yield a 40% probability of offsets being worth an average of $25/tCO2 from 2010 onwards.

Under each of these scenarios, I calculate the "net" change in power plant costs resulting from an EFSEC CO2 standard. This net cost is simply the cost of acquiring offsets minus the risk management benefit of avoiding the need to buy emissions allowance under a future emissions cap, i.e.:

Net cost = Offset acquisition costs – (Avoided allowance costs x Probability of offset validity)

Scenario 1: No risk management benefit
Since under this scenario, the probability of offsets being valid instruments to reduce future allowance costs is zero by definition, the only major economic consideration is the cost of acquiring offsets.

Offset acquisition costs
To first order, calculating offset acquisition costs is relatively straightforward. It is simply the amount of CO2 emissions that need to be offset under a given target (17%, 40%, or 100%) times the assumed price strategy adopted by the rule -- e.g. the Oregon standard, an intermediate $2/tCO2, or the full-market price, which we assume starts at around $3/tCO2 today and increases to $5.5/tCO2 by 2010. Divided by the total kWh produced, this yields the "simple, unfinanced" cost of offsets for a given power plant, as shown in Table 1. On this basis, a CO2 rule stating that 17% of emissions and using the Oregon price formula would appear to add one-hundredth of a cent or 0.2% to the 4.29 cents per kWh (c/kWh) "busbar" cost of producing a kWh of electricity from a new natural gas plant.[15] If all emissions from the plant were offset at the all-inclusive market price of offsets, then this simple approach suggests that offsets would cost an average of 0.15 c/kWh, adding 3.6% to cost of production.

[13] The latter would be equivalent to the "double jeopardy" situation, from a developer's perspective, presented by Dr. Mark Trexler at the EFSEC public hearing.
[14] Future legislation could very well grandfather offsets booked prior to this year – and indeed various climate registry and baseline protection efforts are aimed at this goal – thereby increasing the benefit (i.e. fully rewarding offsets from 2003 through the first compliance date) beyond what is assumed here.
[15] All costs are levelized across the typical 20-year amortization period of a new plant investment. Levelized natural gas costs are projected to be $3.70/MBtu, based on recent NW Power Council medium case estimates.

Table 1. Cost of offsets, simple, unfinanced (cents/kWh)

	Stated offset requirement		
Price (in 2005)	17%	40%	100%
Oregon ($1.3/tCO2)	0.01c *(0.2%)*	0.02c *(0.5%)*	0.05c *(1.2%)*
Int. ($2.0/tCO2)	0.01c *(0.3%)*	0.03c *(0.8%)*	0.08c *(1.9%)*
'All-in' market ($3.7/tCO2)	0.03c *(0.6%)*	0.06c *(1.4%)*	0.15c *(3.6%)*

(Percent shown as fraction of 4.29 cents per kWh busbar cost)

However, the simple approach may underestimate costs, since it presumes that developers would be able to make the five-year upfront offset payments from available cash. It is more likely that the offset requirement will increase developers' financing requirements. Financing of offset payments, in turn, would roughly double the cost of offsets, as shown in Table 2.[16] At the 40% offset requirement and intermediate price of $2/tCO2, financing of offset payments would add 0.06c/kWh (1.4%) compared with 0.03c/kWh (0.8%) in the simple, unfinanced case.

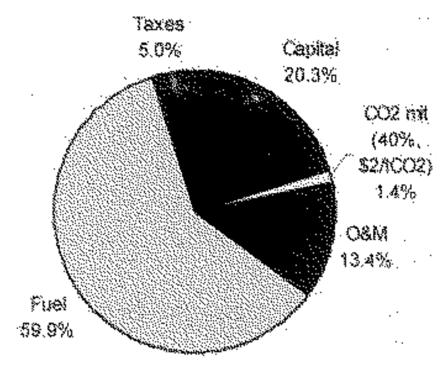
Table 2. Net change in new power plant costs, Scenario 1 - no avoided compliance costs (c/kWh)

	Stated offset requirement		
Price (in 2005)	17%	40%	100%
Oregon ($1.3/tCO2)	0.02c *(0.4%)*	0.04c *(0.9%)*	0.10c *(2.3%)*
Int. ($2.0/tCO2)	0.03c *(0.6%)*	0.06c *(1.4%)*	0.15c *(3.6%)*
'All-in' market ($3.7/tCO2)	0.05c *(1.1%)*	0.11c *(2.7%)*	0.29c *(6.7%)*

(Percent shown as fraction of 4.29 cents per kWh busbar cost)

Figure 1 shows how this 0.06c/kWh offset cost compares with other cost components of a new natural gas plant. Not surprisingly, fuel costs are predominant, and are also highly uncertain, especially in light of price surges and concerns echoed by Federal Reserve chairman Alan Greenspan. If instead of the NPPC's medium gas forecast shown here ($3.70/MBtu levelized 2005-24), their high estimate were realized ($4.56/MBtu, levelized), the cost of electricity production would rise by 0.60 c/kWh, roughly ten times the magnitude of the offset cost imposed under a 40% /$2 mitigation requirement.

Figure 1. Annualized costs for a 540 MW natural gas CCCT



[16] For the purposes of this calculation, I assume that offset payments will be financed on a similar basis as other power plant investments (20 year amortization), except that financing is purely on a debt basis (at 8.7% nominal interest rate).

Box 1. Reflecting actual mitigation amounts

It is important to not that fixing a price below the market cost of offsets effectively reduces the emissions actually mitigated, as is well recognized in the Oregon case. Since the Oregon price (e.g. \$1.28/tCO_2 in 2005) is likely to cover only 34% of the total costs of acquiring offsets (including the administrative costs), under a 17% standard only 6% of emissions would actually be mitigated. At a \$2/tCO_2 price and a 40% standard only 22% would be mitigated. It is important to be explicit this potential discrepancy, so the actual benefits are properly stated and to maximize credibility of the proposed rule. (See Table 3) Any discrepancy in initial price setting is also likely to magnified should offset price escalation be limited to a standard economic price index (such as CPI, PPI), since offset prices are likely to increase much faster than inflation.

Table 3. Actual "mitigation" or offsets purchased given lower-than-market prices

	Stated offset requirement		
Price (in 2005)	17%	40%	100%
Oregon (\$1.3/tCO_2)	6%	14%	34%
Int. (\$2.0/tCO_2)	9%	22%	54%
'All-in' market (\$3.7/tCO_2)	17%	40%	100%

Consumer rates

Increased costs would be reflected either in higher electricity rates or in lost profits by power plant owners. Private and public utility owners would be able to pass on costs to consumers directly, whereas merchant power plant developers would likely absorb much of the added cost in lost profits until a significant fraction of the market is subject to similar costs. Assuming, however, that all offset costs were somehow passed on to consumers, I estimate that by 2010 that rates would rise by from two thousandths of a cent (17% target, Oregon price) to three hundredths of a cent (100% target, full market price), as shown in Table 4.[17]

[17] For the purposes of this calculation, I have assumed that all growth in demand in the Pacific Northwest -- projected to be about 200aMW per year -- is met by new natural gas CCCT plants subject to the CO2 rule. Using this assumption about 8% of generation is subject to this charge in 2010, while about 14% is by 2020. These assumptions are likely to significantly overstate the amount of natural gas capacity built, given competition from other sources of supply within and outside the region. At the same time, however, some capacity may be built in the region for the purposes of displacing older or more costly sources throughout the West.

Table 4. Change in consumer rates, 2010, Scenario 1 - no avoided compliance costs (c/kWh)

Price (in 2005)	Stated offset requirement 17%	40%	100%
Oregon ($1.3/tCO2)	0.002c *(0.0%)*	0.004c *(0.1%)*	0.010c *(0.2%)*
Int. ($2.0/tCO2)	0.003c *(0.0%)*	0.006c *(0.1%)*	0.015c *(0.3%)*
'All-in' market ($3.7/tCO2)	0.005c *(0.1%)*	0.011c *(0.2%)*	0.028c *(0.5%)*

Assuming 8% or 1712 aMW of electricity from NG CCCTs in PNW subject to CO2 rule
Assuming built 2005-2010, subject to increasing offset prices
Assuming current average rate of 5.3c/kWh

Under the 40% target and $2/tCO2 case, rates would rise about 0.006 cents, and average monthly bill would go up 8 cents for the average household, 53 cents for the average commercial customer, and $5.52 cents for the industrial customer (See Table 8 below). By 2020, these effects would just about double.

Scenario 2: Full risk management benefit
Just as the first scenario represents the most pessimistic, this scenario reflects the most optimistic outlook for recovering offset investments in the form of avoided future allowance costs. In this case, if we assume that all offsets purchased under an EFSEC rule are considered valid and interchangeable with emissions allowances under a future cap-and-trade system, at an average value of $25/tCO2 from 2010 onwards, these offsets take on a significant financial value, as shown in Table 5.

Table 5. Full value of offsets under a future cap-and-trade system (c/KWh)

Price (in 2005)	Stated offset requirement 17%	40%	100%
Oregon ($1.3/tCO2)	0.04c *(1.0%)*	0.10c *(2.3%)*	0.25c *(5.9%)*
Int. ($2.0/tCO2)	0.07c *(1.6%)*	0.16c *(3.7%)*	0.39c *(9.2%)*
'All-in' market ($3.7/tCO2)	0.12c *(2.9%)*	0.29c *(6.8%)*	0.73c *(17.1%)*

At 25/tCO2 allowance price, 2010 onwards
(Percent shown as fraction of 4.29 cents per kWh busbar cost)

Offsets in this case are worth from 0.04 to 0.73 cents per kWh[18], and when subtracted from the cost of buying the offsets, the net effect on electricity costs drops from 0.6% to 10.3%, as shown in Table 6. At a 40% target and $2/tCO2 price, the long-term cost of electricity drops by a tenth of a cent or 2.2%, and the maximum impact of consumer rates would be a drop of about 0.1% (see Table 8).

[18] Avoided compliance costs are discounted back to 2005 and levelized across the life of the power plant.

Table 6. Net change in new power plant costs, Scenario 2 - full avoidance of compliance costs (c/kWh)

	Stated offset requirement		
Price (in 2005)	17%	40%	100%
Oregon ($1.3/tCO2)	**-0.03c** *-(0.6%)*	**-0.06c** *-(1.4%)*	**-0.15c** *-(3.6%)*
Int. ($2.0/tCO2)	**-0.04c** *-(0.9%)*	**-0.10c** *-(2.2%)*	**-0.24c** *-(5.6%)*
'All-in' market ($3.7/tCO2)	**-0.08c** *-(1.8%)*	**-0.18c** *-(4.1%)*	**-0.44c** *-(10.3%)*

Assuming full transferability of offsets at 25/tCO2 allowance price
(Percent shown as fraction of 4.29 cents per kWh busbar cost)

Scenario 3: Partial risk management benefit
The third scenario represents an intermediate case, recognizing that neither the pessimistic "Scenario 1" or optimistic "Scenario 2" outlook for the future value of offsets is likely to be correct. The precise likelihood and magnitude of offsets value depends on the many factors described above: likelihood of a cap, its stringency and resulting CO2 permit costs, the fungibility of offsets in this system, and ultimately the perceived quality of offsets themselves. Thought these are highly uncertain factors, EFSEC is not without influence. State and local actions, such a meaningful EFSEC CO2 rule, create increased pressure for national emissions caps. And EFSEC rules for how offsets are acquired will inevitably affect their perceived quality.

As illustrated in the Table 7, if one assumes that, on average, offsets acquired under an EFSEC rule have a 40% probability of being worth $25/tCO2 from 2010 onwards, then the avoided compliance costs roughly cancel the costs of buying offsets, and the rule has no net overall economic impact.

Table 7. Net change in new power plant costs, Scenario 3 - some avoided compliance costs (c/kWh)

	Stated offset requirement		
Price (in 2005)	17%	40%	100%
Oregon ($1.3/tCO2)	**0.00c** *(0.0%)*	**0.00c** *(0.0%)*	**0.00c** *(0.0%)*
Int. ($2.0/tCO2)	**0.00c** *(0.0%)*	**0.00c** *(0.0%)*	**0.00c** *-(0.1%)*
'All-in' market ($3.7/tCO2)	**0.00c** *(0.0%)*	**0.00c** *(0.0%)*	**-0.01c** *-(0.1%)*

Assuming 40% transferability of offsets at 25/tCO2 allowance price
(Percent shown as fraction of 4.29 cents per kWh busbar cost)

Assuming costs and benefits are passed on equally to consumers, there is, not surprisingly, there would be almost no effect on consumer bills, as shown in Table 8 below. Together these three scenarios can be thought of as bracketing the range of impacts this rule would have, under the assumptions used here.[19]

[19] An accompanying spreadsheet is available for reviewing all assumptions and conducting sensitivity analyses.

Table 8. Monthly bill impact, 2010, assuming $2/tCO2, 40% requirement

Price (in 2005)	Residential	Commercial	Industrial
Scenario 1 - No risk management benefit	$0.08	$0.53	$5.52
Scenario 2 - Full risk management benefit	-$0.10	-$0.65	-$6.72
Scenario 3 - Partial risk management benefit	$0.00	-$0.01	-$0.08

Based on USDOE data for WA rates and average bills by class, 2001
Assuming 8% or 1712 aMW of electricity from NG CCCTs in PNW subject to CO2 rule
Actual savings in Scenarios 2 and 3 will be lower than shown to the extent compliance costs are lower in early years of cap-and-trade system.

Conclusions

As is clear from its extensive questions and deliberations with public stakeholders, EFSEC is considering many potential options and outcomes with respect to its proposed CO2 rule. In keeping with this broad view, EFSEC commissioners may wish to consider how these options might interact with serious federal action to address the climate problem. Many observers are convinced that mandatory US emissions caps are, if not inevitable, at least required if we are to take the challenge of climate stabilization seriously. However, there is great uncertainty as to when they will be adopted, how stringent they will be, their cost implications, and the extent to which offset investments made under an EFSEC rule would be deemed creditable towards future emissions targets. As this analysis shows, resolution of these uncertainties is central to how the economics of this rule will ultimately play out.

Under the most pessimistic scenario (#1) for federal action under which EFSEC-approved offsets would have no added financial value, the costs of power from a new natural gas plant would rise from 0.4% (17% target/OR price) to 6.7% (100% target/market price). Under a 40% target and $2 price strategy, the new power cost would rise 1.4%, and, if the added costs were passed on to consumers, electric rates would rise by 0.1% by 2010, adding 8 cents to the average monthly household bill, 53 cents and $5.52 for the average commercial and industrial customers, respectively. Other uncertainties, such as the cost of gas or the fate of electricity restructuring are likely to have a much more significant impact on consumer costs.

Under the most optimistic scenario (#2) for recovering offset investments – assuming they can count almost fully against future emissions allowances costing at average of $25/tCO2 from 2010 onwards – a proposed EFSEC rule would actually reduce consumer rates and increase developer profits over the long run. In 2010, the average household bill might actually be 10 cents lower, and commercial and industrial customers might see a drop of 65 cents and $6.72, respectively, assuming a 40% target and $2/tCO2 fixed price.

Under an intermediate scenario (#3), where the combined probability of having a mandatory emissions cap-and-trade system and of EFSEC-required offsets being valid under that system comes to about 40%, the effect on power plant costs and rates is roughly a wash. This breakeven point is equivalent to assuming that from 2005 onwards emissions from all new plants will pose a liability of about $9/tCO2. This metric is similar to what Pacificorp already uses for planning purposes; its recent Integrated Resource Plan assumed that new fossil plants will have to pay

\$8/tCO2 emitted.[20] Both of these values reflect attempts to quantify three of the four key uncertainties noted above: the likelihood of future emissions caps, timing and extent of these caps, and the price of emissions allowances under such a cap. The other uncertainty, which is not addressed in Pacificorp IRP analysis, is the fungibility of EFSEC-required offsets in a cap-and-trade system.

To maximize future offset value, I strongly recommend that EFSEC create a process that encourages best practice on key issues such as baselines and additionality, leakage and permanence, and monitoring and verification. In this regard, EFSEC can look to standards being developed by the Executive Board of the Clean Development Mechanism, by the World Resources Institute and World Business Council for Sustainable Development, who will soon release their first GHG Protocol for project-based activities, and by the California Climate Registry. In addition, there are the many lessons learned by Climate Trust, Seattle City Light, and the Oregon Office of Energy.

The future liability posed by CO2 emissions from new, long-lived power plants may be very significant. If owners of 540 MW NG CCCT in service in 2005, were required to hold emissions allowance for each ton of CO2 emitted at an average of \$25/t from 2010 onward through its 30 year life, the net present value of this liability would come to \$380 million (NPV), exceeding the total cost of the plant investment itself (about \$330 million). This suggests that the less investment in mitigation done now, the greater the potential future liabilities.

This analysis has focused on a very narrow conception of economic costs and benefits – those related directly to the price of electricity production and use. However, regardless of whether one includes the liabilities for future emissions are counted in the balance sheet, they represent real economic costs to society at large, the hard-to-quantify damages from an incrementally altered climate.

[20] Pacificorp's IRP assumes a base case wherein CO2 allowance costs are \$8/tCO2 starting in FY2009. http://www.pacificorp.com/File/File25682.pdf