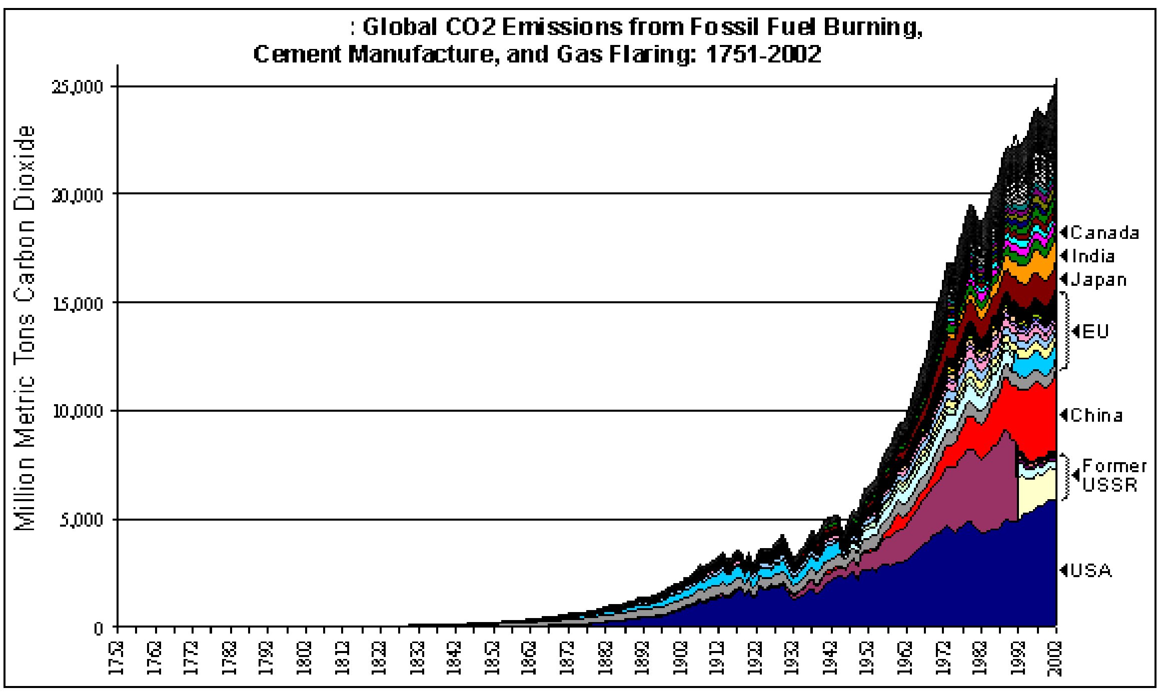
## Chapter 4 Environmental Issues

The environmental issues related to meeting power demands are numerous. They include land and water use issues, impacts on wildlife and plants, emissions related to generation including mercury, SOx, NOx, particulates and greenhouse gases (GHGs).

### Carbon Dioxide

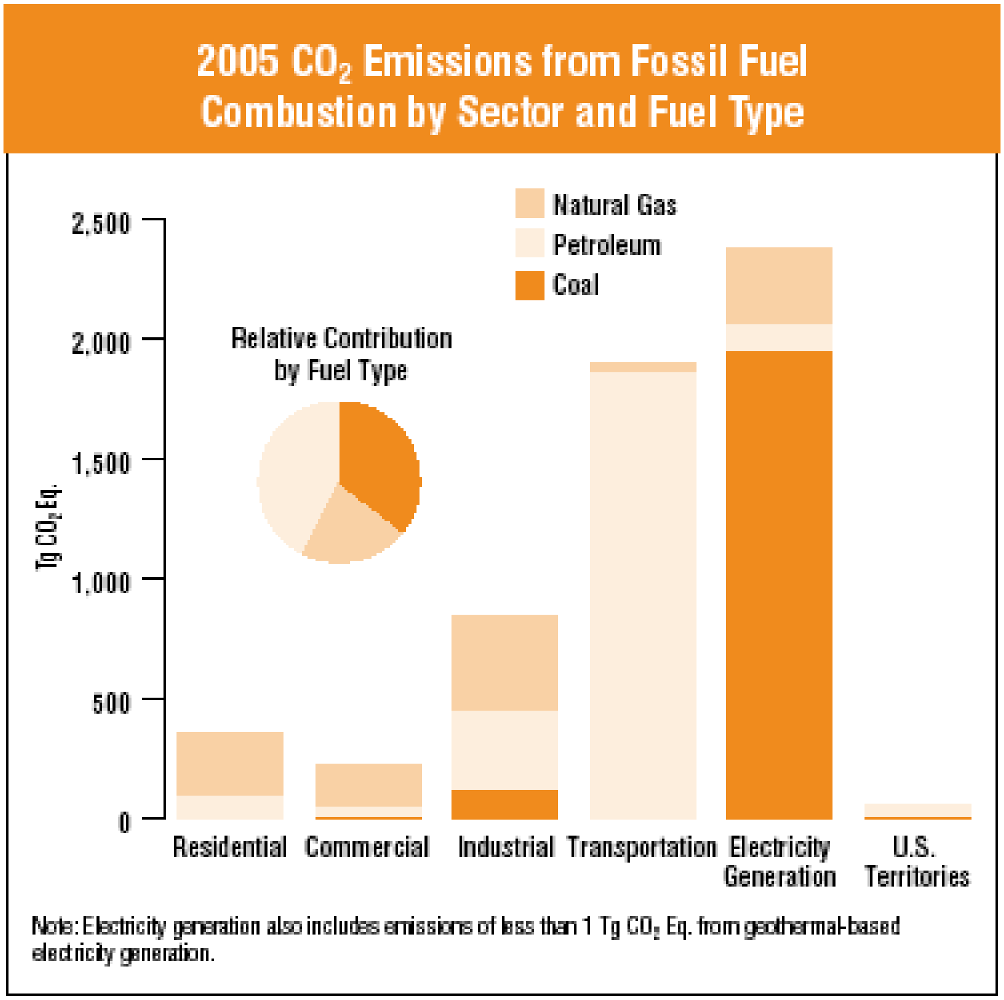
By far, the predominant environmental issue when considering the meta-level decisions about which generation types are best for the portfolio is the emission of greenhouse gases, particularly carbon dioxide. Looking at the historical trend, the emission of carbon dioxide worldwide has risen precipitously, particularly in the United States. See the global carbon emissions Figure 4-1 below. The single largest source of man-made carbon dioxide emissions is power production. Figure 4-2 shows the emissions by fuel type from power production.

Figure 4-1, Global Carbon Emissions




Source: From the EPA - www.epa.gov/climatechange/emissions/globalghg.html

Figure 4-2. 2005 $CO_2$ Emissions from Fossil Fuel Combustion by Sector and Fuel Type




Source: From EPA 's report "U.S. Greenhouse Gas Inventory Reports" Executive Summary page ES-7.

With mounting public and political pressure to address these trends, it is becoming more certain that regulatory steps will be taken. The questions are what steps will be implemented, what will they be from a policy perspective, how will resources costs be impacted, and what limitations will be placed on resource construction in a narrow sense.

Other regional utilities are engaged in resource planning and are attempting to balance the competing objectives of growing loads, projected deficits, costs, risks, and environmental stewardship. It is instructive to review what these entities have done to address the pressing environmental issues. Volume 2, Chapter 1 contains a summary of how other regional utilities have addressed environmental mitigation in their integrated resource planning processes. Volume 2, Chapter 4 provides the MIT Coal study.

NorthWestern Energy's 2005 Procurement Plan

In the 2005 Plan, NorthWestern modeled the portfolio costs using an expected and high projection of $CO_2$ cost adders. The expected case costs were projected as $6.00/ton from 2010-2016, increasing to $14.00/ton thereafter. The high cost projection was set at $18.00/ton for the 2010-2016 period and rising to $41.00/ton thereafter. These different scenarios were applied to the portfolios and the financial results under each case were analyzed.

NorthWestern Conclusions

Given the high degree of uncertainty regarding future carbon adders, whether applied through a carbon emissions tax or a cap and trade system, it is prudent to model various levels of future costs associated with the emission of carbon. A tax would be a level of charges applied by the government for the emissions of carbon. A cap and trade system is a mechanism where the government set a limit on the amount of emissions through some form of allotment, and then allows the exchanging or trading of the allotments on the open market.

NorthWestern reviewed various other sources of carbon cost adders and decided, for purposes of this Plan, to model three different levels of carbon adders for each resource and thus all portfolios. The sources used for benchmarking were the MIT Future of Coal Study, (included in Volume 2, Chapter 4) and recent IRPs by Portland General Electric, PacifiCorp, Idaho Power, and Avista. The medium case adder was derived by averaging the first year (2010) medium case from these sources, and then escalating that first year cost by 2.5% annually thereafter. This 20-year carbon tax price curve was then visually compared to the other curves for reasonableness before finalizing the adoption of the curve. For the high cost case, the high case from the MIT study was adopted without alteration. The low case was constructed recognizing the aggressive timing reflected in the 2010 start dates for the other carbon adder cases. The low case is the same curve as the medium case, but with a six-year lag in implementation to 2016. This broad range of carbon adders will provide an understanding of how different portfolios will perform with different levels of carbon costs applied. The results of the benchmarking process are displayed in Table 4-1, Figure 4-3, and 4-4 shown on the following pages.

## Table 4-1, Carbon Emissions Cost Adders

*Carbon Emissions Cost Adders – in Nominal $ per ton CO2 emitted.*

| | NWEN 2005 | | MIT FofCoal Study | | PGE | | PAC | | IPC | Avista 2007 | | EU Forward Price | NWEN 2007 | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Year | Expected | High | Low | High | Expected | High | Expected | High | Expected | Expected | High | | Low | Medium | High |
| 2007 | | | | | | | | | | | | $0.10 | | | |
| 2008 | | | | | | | $8.00 | $39.90 | | | | $27.36 | | | |
| 2009 | | | | | | | $8.20 | $40.90 | | | | $27.96 | | | |
| 2010 | $6.00 | $18.00 | $9.65 | $9.65 | $7.72 | $40.00 | $8.41 | $41.92 | $14.73 | $7.34 | $25.37 | $28.58 | $- | $9.57 | $9.65 |
| 2011 | $6.00 | $18.00 | $10.37 | $10.37 | $8.11 | $42.00 | $8.62 | $42.97 | $15.19 | $7.64 | $26.74 | $29.21 | $- | $9.81 | $10.37 |
| 2012 | $6.00 | $18.00 | $11.15 | $11.15 | $8.51 | $44.10 | $8.83 | $44.04 | $15.80 | $7.94 | $28.19 | $29.83 | $- | $10.05 | $11.15 |
| 2013 | $6.00 | $18.00 | $11.99 | $11.99 | $8.94 | $46.31 | $9.05 | $45.14 | $16.19 | $8.26 | $29.71 | | $- | $10.31 | $11.99 |
| 2014 | $6.00 | $18.00 | $12.89 | $12.89 | $9.38 | $48.62 | $9.28 | $46.27 | $16.59 | $8.59 | $31.31 | | $- | $10.56 | $12.89 |
| 2015 | $6.00 | $18.00 | $13.85 | $38.99 | $9.85 | $51.05 | $9.51 | $47.43 | $17.01 | $8.94 | $33.00 | | $- | $10.83 | $38.99 |
| 2016 | $6.00 | $18.00 | $14.89 | $41.53 | $10.35 | $53.60 | $9.75 | $48.61 | $17.43 | $9.30 | $34.78 | | $9.57 | $11.10 | $41.53 |
| 2017 | $14.00 | $41.00 | $16.01 | $44.23 | $10.86 | $56.28 | $9.99 | $49.83 | $17.87 | $9.67 | $36.66 | | $9.81 | $11.38 | $44.23 |
| 2018 | $14.00 | $41.00 | $17.21 | $47.10 | $11.41 | $59.10 | $10.24 | $51.08 | $18.32 | $10.06 | $38.64 | | $10.05 | $11.66 | $47.10 |
| 2019 | $14.00 | $41.00 | $18.50 | $50.16 | $11.98 | $62.05 | $10.50 | $52.35 | $18.78 | $10.47 | $40.72 | | $10.31 | $11.95 | $50.16 |
| 2020 | $14.00 | $41.00 | $19.89 | $53.42 | $12.58 | $65.16 | $10.76 | $53.66 | $19.24 | $10.89 | $42.92 | | $10.56 | $12.25 | $53.42 |
| 2021 | $14.00 | $41.00 | $21.38 | $56.89 | $13.20 | $68.41 | $11.03 | $55.00 | $19.73 | $11.32 | $45.23 | | $10.83 | $12.56 | $56.89 |
| 2022 | $14.00 | $41.00 | $22.98 | $60.59 | $13.86 | $71.83 | $11.30 | $56.38 | $20.22 | $11.78 | $47.67 | | $11.10 | $12.87 | $60.59 |
| 2023 | $14.00 | $41.00 | $24.71 | $64.53 | $14.56 | $75.43 | $11.59 | $57.79 | $20.72 | $12.25 | $50.25 | | $11.38 | $13.19 | $64.53 |
| 2024 | $14.00 | $41.00 | $26.56 | $68.73 | $15.29 | $79.20 | $11.88 | $59.23 | $21.24 | $12.74 | $52.96 | | $11.66 | $13.52 | $68.73 |
| 2025 | $14.00 | $41.00 | $28.55 | $73.19 | $16.05 | $83.16 | $12.17 | $60.71 | $21.77 | $13.25 | $55.81 | | $11.95 | $13.86 | $73.19 |
| 2026 | | | | | | | | | | $13.79 | $58.83 | | $12.25 | $14.21 | $77.95 |
| 2027 | | | | | | | | | | $14.34 | $62.00 | | $12.56 | $14.56 | $83.02 |
| FLAT Starting 2010 | $9.23 | $27.29 | $15.50 | $33.11 | $10.50 | $54.43 | $9.97 | $49.72 | $17.41 | $9.63 | $36.75 | | $5.35 | $11.29 | $35.62 |

Figure 4-3, $CO_2$ Tax Projections – Expected/Low

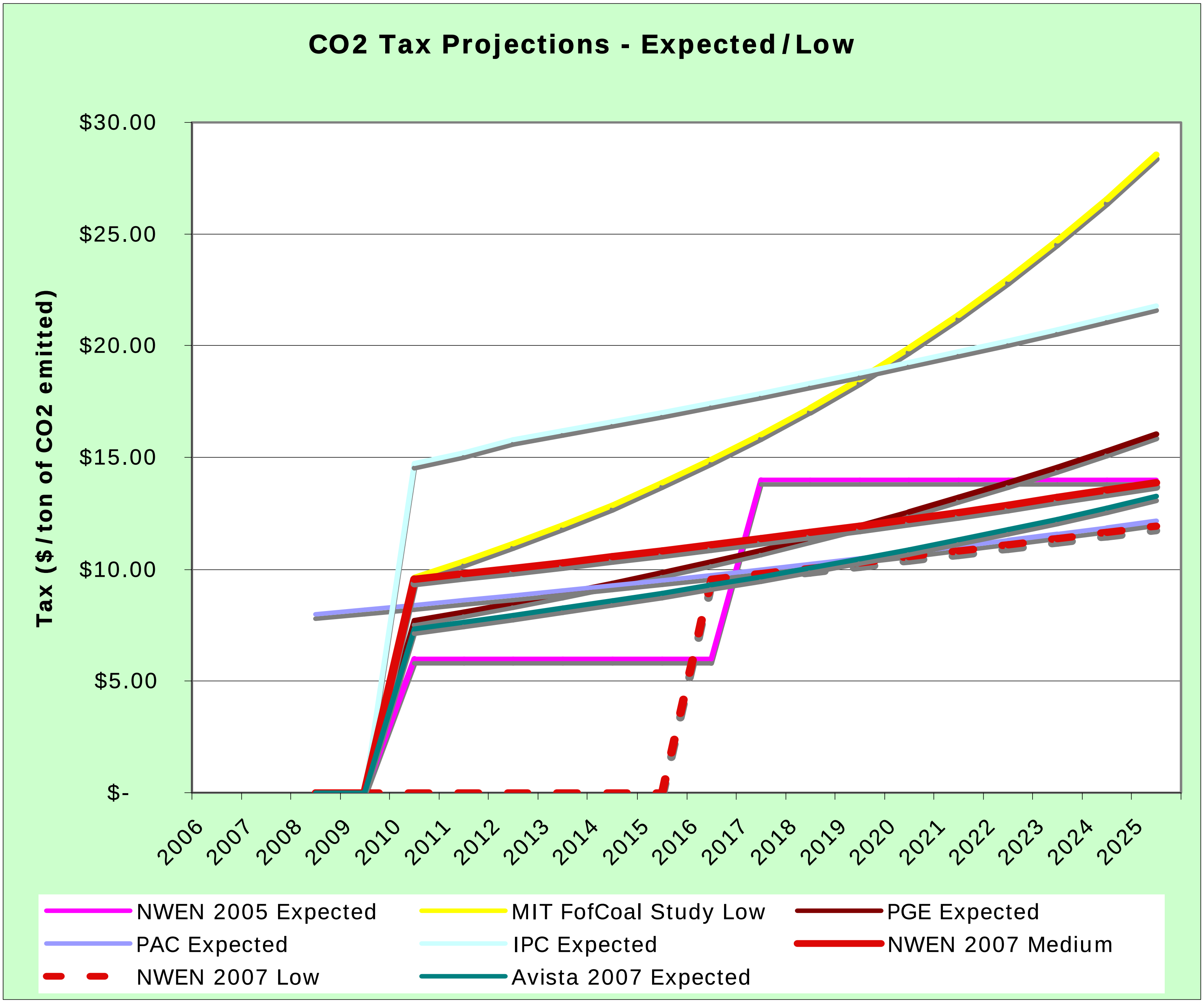
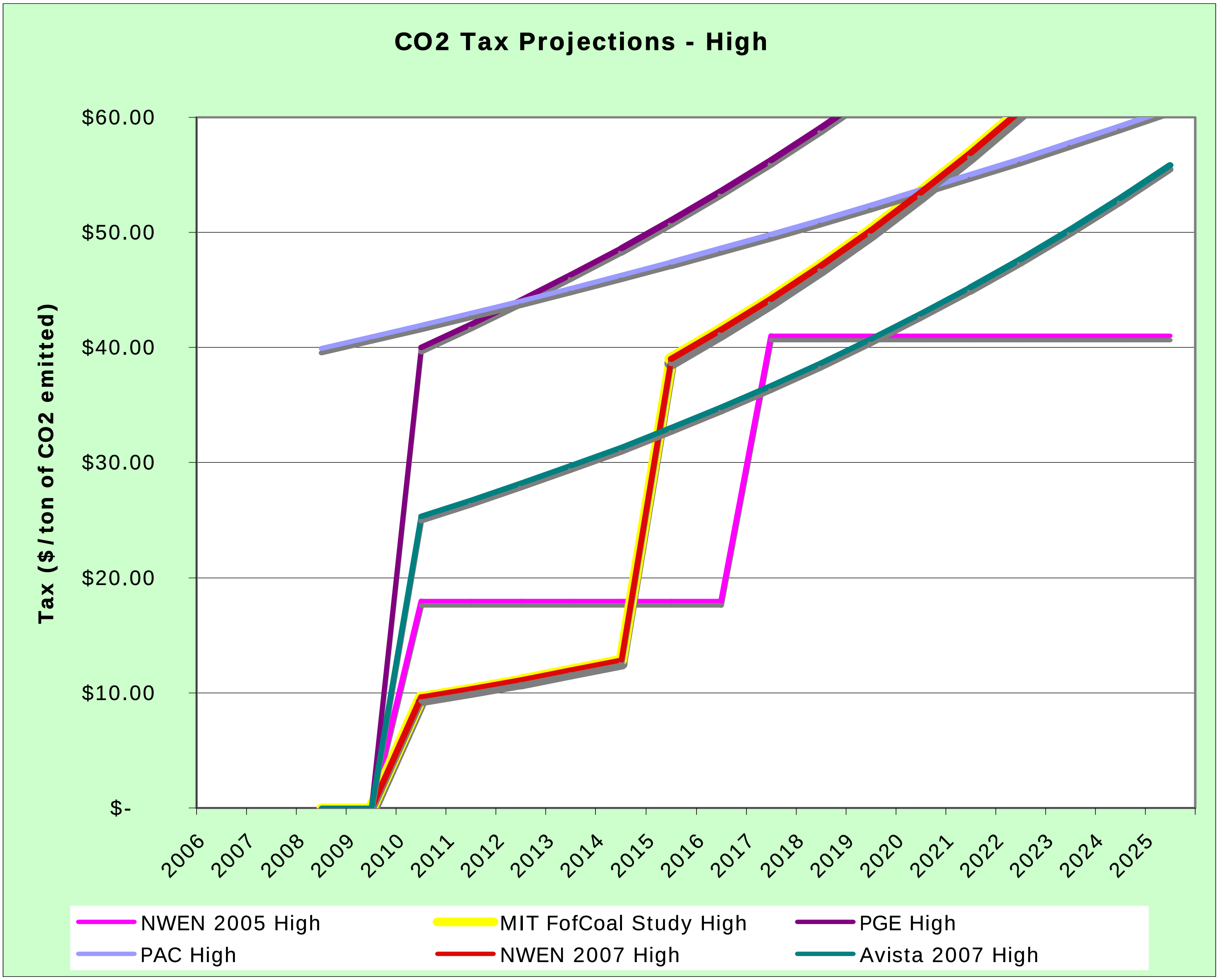


Figure 4-4, $CO_2$ Tax Projections – High



Resource Emissions

In developing the resource $CO_2$ emissions in the Plan, NorthWestern assigned each resource a carbon output rate per MWh. This emission rate was highest for pulverized coal plants and lowest for renewables. Table 4-2 below shows the carbon emission rates of all the new resource options modeled.

Table 4-2, Carbon Emission Rates Modeled

Carbon Emission Rates – New Resource Options Modeled

| Resource | $CO_2$ Emissions (tons $CO_2$ emitted per MWh produced) |
|---|---|
| Coal - PV Subcritical | 1.012 |
| Coal - PV Supercritical | 0.915 |
| Coal - IGCC | 0.791 |
| Gas - SCCT Aero | 0.582 |
| Gas - Internal Combustion | 0.582 |
| Gas - LMs | 0.582 |
| Generic Regulating Resource | 0.582 |
| Gas - CCCT | 0.429 |
| Gas - CHP | 0.429 |
| Gas - Oil Sands | 0.429 |
| Gas - SCCT Frame | 0.365 |
| Coal - PV Sub w/ CCS | 0.140 |
| Coal - PV Super w/ CCS | 0.120 |
| Coal - IGCC w/ CCS | 0.081 |
| Gas - CCCT w/ CCS | 0.040 |
| Biomass | 0.000 |
| Geothermal | 0.000 |
| Wind | 0.000 |
| Solar - PV | 0.000 |
| CAES | 0.000 |
| Pumped Storage | 0.000 |

The unsequestered coal plants are the highest emitters at approximately a ton of $CO_2$ emitted for each MWh of electricity produced. Sequestration efforts, noted by CCS, appear promising as they are estimated to capture and sequester approximately 90% of the carbon output. Although efforts are underway to construct larger scale facilities, the sequestration technology is still in the experimental stage. The sequestration comes with a price as capital costs are increased substantially for the additional equipment needed and the capture and sequestration technology places a significant parasitic load on the projects, reducing their overall efficiency. The carbon sequestration, however, does reduce the coal-fired generation emission output to well below the non-sequestered natural gas fired units. Biomass was modeled as carbon neutral, even though $CO_2$ is emitted during generation, because the carbon emitted is equivalent to the carbon that was captured through the growth of the feedstock for the plant.

In modeling the resource portfolios, the carbon output of each plant was included as an operating parameter in the GenTrader® runs as an increased variable cost derived by combining the emission rate for each plant with the projected carbon cost adder for the scenario. This is a significant change compared to the modeling effort in the 2005 Plan. By including the carbon cost to the units in the resource dispatch logic, the trade offs that will occur in the wholesale markets between high and low carbon-emitting projects is appropriately modeled and the resulting impacts on dispatch decisions captured. In the 2005 Plan, the potential carbon impacts on the portfolios were included as an extra resource cost calculation that was added after the detailed modeling was performed, which addressed the cost impact in a less sophisticated manner.

**Other Environmental Emissions**

Of course, generating resources tend to emit other pollutants besides greenhouse gases. Of concern are the emissions of mercury, SOx and NOx. The risk premium related to the emission of these pollutants, however, is largely overshadowed by the extreme uncertainty related to the $CO_2$ risk. This does not mean that the issues related to these other pollutants should be disregarded, however. Currently, the cost uncertainty associated with the emissions of SOx and NOx seems to have stabilized and can be addressed through the inclusion of Best Available Control Technology (“BACT”) in new resource construction. This regulatory standard has been in place since the late nineties and is well understood. The current environmental and political climate does not appear poised to add any significant future costs to generating plants that were built to this standard. For these reasons, the SOx and NOx related to various plant choices is noted, but attempts to reduce the emissions rate to an explicit cost externality were not undertaken.

Of greater concern is the emission of mercury. Prior to the advent of the current high state of concern over GHGs and global climate change, it appeared that the emission of mercury would be the primary environmental concern related to the construction of new power plants. In March 2005, the EPA issued the Clean Air Mercury Rule ("CAMR") creating regulatory limits and establishing a market based cap and trade process to reduce the amount of mercury emissions from power plants. The desired goal is a 70% reduction in mercury emissions. The first phase of CAMR relies on co-benefits, or reductions in mercury resulting from efforts to reduce NOx and $SO_2$ and sets defined limits for coal plants based on the form of $SO_2$ control technology employed. The lower limit, for wet $SO_2$ controls is .042 lbs/GWh of energy produced. The representative new coal units (shown in Table 4-3 below) modeled in this Plan have mercury emission rates which are approximately half of this rate, representing the use of improved mercury control technology.

Table 4-3, Coal Unit Emissions

| Plant | Hg Emission Rate (lbs/GWh) |
|---|---|
| Coal - PV Subcritical | 0.02 |
| Coal - PV Sub w/ CCS | 0.024 |
| Coal - PV Supercritical | 0.02 |
| Coal - PV Super w/ CCS | 0.024 |
| Coal - IGCC | 0.0126 |
| Coal - IGCC w/ CCS | 0.0148 |

The second phase of CAMR establishes a market-based cap and trade system that includes specific state-by-state mercury emissions limits, beginning in 2010 and stepping down in 2018. The 2018 limits are much more stringent, with Montana's allocation dropping from 0.378 tons to 0.149 tons. It is conceivable that this reduction in allowed mercury emissions related to coal plants will have a cost impact on NorthWestern's supply portfolio costs, but it is very unclear at this time what that cost impact will be. At this time, the potential impacts of mercury emission limits are noted and explicit cost impacts are not included in the modeling effort.