Review of the DEC Division of Air Quality

"*Final Emission Fee Rate Evaluation Report*"

prepared for

Thomas Turner
Division of Air Quality
Alaska Department of Environmental Conservation

prepared by

Alexandra Hill
Steve Colt
Institute of Social and Economic Research
University of Alaska Anchorage

27 June 2008

contact:
Lexi Hill
anarh1@uaa.alaska.edu
786-5436

Introduction

In its “Final Emission Fee Rate Evaluation Report,” dated October 9, 2006 (hereafter: the *report*), the Division of Air Quality (hereafter: “the Division”) undertakes the following tasks:

- Project future workloads and costs for the Title 5 permit program
- Project future workloads and costs for the Title 1 permit program
- Project permit administration fee revenues for Title 5 and Title 1 permits
- Project future workloads and costs for other (non permit-related) Air Program activities
- Project the amount of emissions to be regulated under the Air Program
- Based on projected program costs, permit administration fees, and emissions, determine the emission fees necessary to recover the full costs of the Title 5 and Title 1 permit programs.
- Consider cost-saving measures, alternative funding sources, and alternative fee structures
- Recommend actions on emission fee rates, other funding, and changes in program operations

ISER researchers were asked to review this report to determine if:

1.) the methodology used was appropriate;

2.) the methodology was accurately applied;

3.) all relevant data was included in the analysis, and

4.) the conclusions reached were justified by the analysis.

In this review we address each of these questions in turn.

1. Was the methodology used appropriate?

1.1 General economic principles

As noted in the *report*, the emission fees in question are designed “to recover costs incurred by the department and other state or local governmental agencies” (p. 1). According to the *report*, the fee program must meet at least the following two tests: First, the aggregate amount of fees collected must be sufficient to defray the aggregate amount of costs incurred. Second, there must be an “equitable apportionment” of the total aggregate cost to individual emitting entities.

These two tests are largely analogous to the tried-and-true concepts of cost recovery and cost allocation used in the practice of public utility ratemaking.[1] In forming rates that are "just and reasonable," utility regulators attempt to ensure that the total revenue requirement of the utility can be recovered through rates and that the individual rates are the result of a rational and equitable allocation of the total revenue requirement among the various ratepayers. While we are not suggesting that emission fees are the same thing as electricity rates, we do believe that the process of utility ratemaking is the most fully-developed example of prices that are set administratively rather than in a competitive market. Utility ratemaking has been subject to continuous scrutiny by courts, legislators, and the public. The principles developed have evolved and improved in response to that scrutiny.

Utility ratemaking practice provides some additional general guidance as to how costs should be apportioned, although debates about details always occur and ratemaking proceedings conducted by regulatory commissions are almost always long and arduous. The most salient pieces of general guidance are:

- The **cost-causer should be the cost-payer** to the extent reasonably possible
- **joint costs** should be allocated based on some transparent and observable basis. In the case of electricity, for example, the cost of transmission line construction is sometimes allocated to users based on electric energy consumption.
- the rate structure should be **simple and feasible** to implement, given that it meets the above criteria. Clearly the definition of "simple and feasible" will depend on the available computer systems and software.

We have applied these general concepts from economic theory and utility ratemaking practice to our review of the emissions fee development process described in the *report*.

[1] See, e.g.:
Bonbright, James; Danielsen, Albert; Kamerschen, David. 1988. Principles of Public Utility Rates. Arlington, VA: Public Utilities Reports, Inc.
Brown, Stephen; Sibley, David. 1986. The Theory of Public Utility Pricing. Cambridge UK: Cambridge University Press.
Phillips, Charles. 1993. The Regulation of Public Utilities. Arlington, VA: Public Utilities Reports, Inc.

1.2 Appropriateness of methodology

The primary method of analysis throughout the *report* is to begin with historical information from FY03, FY04 and FY05 to estimate total and average workloads, costs, and revenues per year. These historical averages of actual costs serve as a guide for staff to project forward, adjusting for expected changes. Projected costs and projected emissions together determine the emission fees necessary to cover those costs. Overall, this method is analogous to utility ratemaking. In fact, it is superior due to its use of multiple years to form the historical base (most utility rate cases are based on a single "test year".)

Given the short projection period of four years (FY07 through FY10) and the staff's detailed knowledge of the program, this is an appropriate methodology. (By contrast, projection based on the recent past would NOT be appropriate for a long-term future period such as the years FY10 through FY20.) Of course, the devil is in the details: the quality of the resulting analysis and the resulting fees will depend on several factors. Chief among these are the availability of good historical data, the ability to foresee the degree to which the future will reflect or differ from the past, and the accuracy of costs estimates for new activities. The *report* consistently cites the sources of the data used and clearly describes how the historical data are used to project future workloads, costs, and revenues. Where historical data are not available, and where circumstances have changed, staff judgments about how they derived or adjusted the projected costs are explained.

2. Was the methodology accurately applied?
and
3. Were all relevant data included in the analysis?

The authors of the analysis faced several challenges in trying to base fees on actual data. Some data were not available, and some data varied so much from year to year that its predictive power was limited. This section reviews the analysis, discussing how it addresses the various data issues.

Title 5 permits

The *report* considers the Air Quality programs in three major components: Title 5 permits, Title 1 permits, and other program activities. We review Title 5 in some detail, as it is illustrative of the approach used throughout.

Title 5 permits are primarily permits for major stationary air pollution sources. The federal Clean Air Act requires that the cost of the Title 5 permit program be fully defrayed by user fees. Alaska collects those user fees as permit administration fees (where costs can be directly allocated to users) and emission fees (which users pay based on their emissions, and which must fully fund the costs of the Title 5 program not covered by permit administration fees). The *report* calculates the necessary level of emission fees, while permit administration fees are set using a different process. However, permit administration fees can affect emission fees because if permit administration fees don’t fully cover the costs of permit administration then any shortfall must be collected in the form of emission fees.

The department’s analysis first projects the costs of Title 5 program activities. These include permit actions, compliance actions, data management, administration, and program improvement efforts. Revenue projections -- permit administration fees and the expected balance in the Clean Air Protection Fund -- are then considered. The difference between costs and these revenues provides the projected total amount that must be collected from emission fees. The department then projects total emissions subject to Title 5 emission fees in order to calculate the necessary emission fee rate in dollars per ton.

Permit and compliance actions

For permit actions, data from FY03 through FY05 on the number of actions, technical hours billed for each type of action, and staff knowledge (for example, knowledge when permits are due for renewal) were used to project workloads and the staff hours need to accomplish those workloads for FY07-FY10. These calculations are a straightforward application of historical technical hours per action to projected future actions.

For compliance actions, the projected number of compliance actions by type of action was based on historical averages, with modifications based on staff input. However, historical technical hours per action were only available for the total of all compliance actions, not for actions by type. Since there were no data available on the historical technical hours per compliance action by type, the averages used for the projection were based on performance measure standards.

One way to assess the accuracy of those performance standards for the purpose of projection is to apply the standards to historical numbers of actions by type to see if they can reproduce an accurate calculation of actual historical hours. In this case, they do not, for several reasons. When applied retroactively to the FY03-FY06 data, the use of the performance standards leads to an overestimate of total hours (Table 1). However, the report documents the sources of most of the discrepancy.

Table 1. FY03 to FY05 Predicted technical hours base on historical number of actions and performance measure standards for hours per action

	A. Avg tech hrs/ action (Tbl 4)	B. FY03 actions (Tbl 3)	C. FY03 projected hours (A x B)	D. FY04 Actions (Tbl 3)	E. FY04 projected hours (A x D)	F. FY05 actions (Tbl 3)	G. FY05 projected hours (A x F)
Full Compliance Eval - off site	32.6	26	847.6	52	1,695.2	50	1,630
Full Compliance Eval - on site	72.5	31	2247.5	50	3625	44	3,190
Source test plan review	10.9	34	370.6	43	468.7	32	348.8
Source test results review	10.9	46	501.4	27	294.3	35	381.5
Excess emission or permit deviation report	0.7	10,491	7,343.7	3,165	2,215.5	5467	3,826.9
Observe source test	54.3	9	488.7	12	651.6	0	0
Informal Enforcement	21.8	1	21.8	0	0	0	0
Advisory Letter	5.8	2	11.6	1	5.8	2	11.6
Compliance letter	10.9	22	239.8	78	850.2	95	1,035.5
Other compliance agreements	174	28	4872	12	2,088	25	4,350
Total ‘predicted’ hours			16,945		11,894		14,774
Total Hours from Table 3			3,443		7,707		8,737
Number of hours discrepancy			13,502		4,187		6,037
Estimated over-projection due to switching from events to notices in reporting excess emissions actions			6,993		1,866		3,476
Adjusted “predicted’ hours			9,952		10,028		11,298
Estimated hours under-reported			1,721		3,854		4,369
Adjusted “actual” hours			5,164		11,561		11,576
Difference between adjusted predicted and adjusted actual hours			4,788		-1,533		-278

First, the way that excess emissions and permit deviation actions were reported is not consistent through the reporting period. The performance measure standard for average technical hours is designed to be applied to notices. However, prior to February 2005, the system logged events rather than notices. (After February 2005, the system did log notices.) Using notices reported in the first eight months of 2006, the department estimates only about 500 (instead of 5,000 to 10,000) actions per year. This reporting change accounts for about half of the difference between predicted and actual hours. We show the adjusted "predicted" hours in table 1, above. In addition, the appendix notes to table 4 in the *report* state that staff was not correctly reporting compliance action time, resulting in an underestimate of total technical hours for compliance actions of about one-third. We show the adjusted "actual" hours in table 1 as well. While there is still a significant difference in FY03, the performance standard method with these adjustments reproduces actual FY04 and FY05 technical hours within 10 percent.

In trying to project Title 5 permit and compliance activities and costs, staff had to create a projection based on a very short time frame, with regulatory changes that sometimes made the relevant historical time frame even shorter. During much of that time, the tools available for tracking the relevant data on activities accomplished and time spent were not well integrated and didn't collect all the data necessary. In dealing with the various changes in regulations, priorities, data collections, and gaps in data, the *report* presents explanations and reasonable work-arounds. In some cases the explanation is not clear. For example, the *report* states that "Table 3 also calculates the historical average of technical hours per compliance action type." None of the relevant cells in table 3 contain actual data., and the explanation that Performance Measure Standards were used to estimate the missing numbers is not connected to the table. The result is that while the information is in the *report*, it is easy to miss.

As described above, the report uses the projected number of permit and compliance tasks, and the average technical hours needed per task to calculate the total projected technical hours for the "Base Program" for FY07-FY10. Then total historical program costs for FY03 through FY05 are divided by total technical hours for those years to estimate the *total* program cost per *base* program technical hour. The average historical cost per hour is multiplied by the projected technical hours to produce a projected base program cost for FY07 – FY10.

Other Title 5 activities

The Title 5 activities not directly associated with permits or compliance are program improvement, data management, and administrative services. Increased costs for these activities (over the FY03-FY05 level) are added to the base program cost projection. In each relevant section, the *report* details historical costs and activities and anticipated future costs and activities. Since FY03-FY05 costs for these activities were already included in the total program costs used to calculate the total program cost per technical hour, they are already included in the base program cost. The *report* discusses changes in each cost category that are projected to increase costs above those of the historical years. The Division has begun to develop a Quality Management System to improve the speed, accuracy and consistency of permit and compliance actions. They have projected the cost of developing and implementing the new system based on the costs associated with similar projects elsewhere. The division is also continuing to develop an improved data management program, AirTools, that provides a single data system to track all the various aspects of Title 5 and Title 1 permitting and compliance. In the future, AirTools will allow on-line permitting options as requested by industry. Future AirTools development costs have been estimated based on the specific developments and improvements that are planned, personnel time required, and personnel costs of those developing the application.

Changes in administrative costs

Administrative costs increased due to changes in the Permit Administration fee structure, and also due to changes in the Department of Administration's personnel and administrative procedure requirements. The Permit Administration fees changed in response to legislation that replaced a flat hourly rate for permit administration work with a required two-tiered fee structure. The new structure includes both flat fees for some services and a requirement to charge 'actual costs' (including the personnel costs of the specific permit writer doing the work) for services that go beyond those covered by the flat fee.

These changes affect emission fees in two ways. First, the more complex coding of personnel time and appropriate billing requires more administrative support than the old system. The Air Permits program added a new accountant position, and increased the fee-related time demands on several other positions. While the permit writer time that is being billed under the new structure is supposed to be covered by the permit administration fees, the increased administrative demands are not, and must be covered by emission fees. In addition, starting in FY06, the Department of Administration's Division of Personnel added new time reporting requirements and delegated tasks that it had formerly performed to the various divisions that it supports. The cost of those added administrative tasks must also be covered by emission fees.

The second way the new Permit Administration fee structure can affect emission fees is if it results in fees that are more or less than the actual cost of permit administration. If Permit Administration fees are too high, the resulting surplus would reduce emission fees, but if they are too low, the shortfall must be covered by increased emission fees. The report shows that those fees are likely too low. When permit writers charge for actual hours, those charges are set by a previous statute at 149% percent of their hourly salary. Increases in health and retirement costs since the legislature set this 149% rate have driven actual total personnel costs well above 149% of salary. In addition, it's not clear that the flat fee portion of the permit administration fees is adequate to cover the services they are designed to cover; permit administration fee collections have declined substantially under the new structure. While it is beyond the scope of the *report* to analyze the adequacy of the current permit administration fee structure, it does recommend that the two fees be set concurrently, rather than on separate timetables as is now the case. We agree that a concurrent process would likely be more effective because it could take into account the interdependence of the two fees.

Adjustments to base program cost

The final step in projecting total program costs (base program plus new costs of other activities) is to adjust for inflation and for increased PERS costs. The inflation adjustment (applied to the entire cost) is 2.9 percent per year, and the additional PERS contribution (applied only to salaries, which make up only about 65% of program costs) is 5 percent per year. The net effect of these two adjustments is to increase the projected total program costs by an additional 5.8 percent per year. The inflation adjustment is supported by U.S. Bureau of Labor Statistics inflation statistics and the PERS adjustment is mandated by the Alaska Department of Administration.

In order to estimate the amount of emission fees needed to fund the Title 5 program, the analysis must account for other sources of funding: the Clean Air Protection Fund (CAPF) balance carried forward and the Permit Administration Fee revenues. The balance carried forward (from FY06) was estimated at about $600,000. Because of FY06 changes in how Permit Administration fees are calculated, the analysis uses only 9 months of historical data relevant to the projection. The analysis uses these 9 months of data pro-rated to 12 months as the annual projected amount.

Subtracting the expected permit administration fees and the expected CAPF balance gives the amount of program cost that must be covered by emission fees. The department projected assessable emissions based on FY06 actual emissions. When projected program costs to be covered by emissions fees are divided by projected emissions, the resulting emissions fees are more than double the existing level (Table 2).

Table 2. Title 5 Emission fee calculation summary

	Data from	FY07	FY08	FY09	FY10	Average
Title 5 Projected Program Cost	Tbl 12	$2,979,800	$3,832,098	$3,944,134	$3,413,548	$3,542,395
Expected Permit Admin Fees	Tbl 13	$ 775,000	$ 775,000	$ 775,000	$ 775,000	$ 775,000
Expected CAPF Balance	Tbl 14	$ 600,000				
Amt to be covered by emission fees	Tbl 15	$1,604,800	$3,057,098	$3,169,134	$2,638,548	$2,617,395
Projected Emissions	Tbl 28	116,342	116,342	116,342	116,342	116,342
Necessary Fee/Ton	Tbl 34	$ 13.79	$ 26.28	$ 27.24	$ 22.68	$ 22.50
Current Fee (Title 5 portion)	Tbl 35	$ 9.77	$ 9.77	$ 9.77	$ 9.77	$ 9.77

Title 1 Permits and other program activities

The analysis for Title 1 permits is similar. Where historical information is adequate, it is used to project FY07-FY10 activity levels, technical hour requirements, and other costs. Staff revised those projections as necessary to reflect known changes from historical conditions, changes in regulations, or department plans. As with Title 5, projected activities were multiplied by projected technical hours per activity to estimate future total technical hours. Historical technical hours were divided by historical program costs to estimate total program costs per technical hour. These costs per technical hour were multiplied by projected technical hours to calculate a base program cost. Non-permit Title 1 activities- program improvement, data management, and program administration costs were analyzed in the same way as those for Title 5, but with a smaller portion of the costs allocated to Title 1 than to Title 5. Once the base and non-permit program costs were added together, the 5.8 percent per year adjustment for inflation and increasing PERS contributions was applied to estimate total program costs. As with Title 5 permit administration fees, the projection of Title 1 permit administration fees was based on the limited data available since the regulations governing these fees changed.

Title 1 recommended fees

Total (adjusted for inflation and PERS) program costs minus permit administration fees produces the amount of Title 1 program cost that potentially must be covered by emissions fees. Unlike the Title 5 program, federal law does not require fees to cover all Title 1 program costs – they may be funded by other sources, such as state general funds. However, there are other Air Program duties (detailed in *report* section 5), that have no fees associated with them and must be covered from state and federal funds. The cost of these activities is projected to rise a small amount from additional regulation development, but more significantly from the 2.9% inflation and 5% PERS annual increases. Current levels of funding from a federal Air Program 105 grant and state general funds are inadequate to meet these rising costs, let alone leave money available for offsetting Title 1 emissions fees.

Dividing the projected portion of Title 1 program cost that must be covered by fees by projected emissions amounts produces large percentage increases in Title 1 emissions fees. Faced with proposing large increases in both Title 5 and Title 1 emissions fees, the Division analyzed several options to (1) spread fees over a larger group (apply fees to emission sources under 10 tons; apply fees to those who currently pay an “avoidance” flat rate; add new Title 1 application fees, change regulations to increase permit administration fees) and/or (2) to cut costs (abandon the QMS initiative to improve program management, eliminate negotiation and permitting assistance on flat fee projects, reduce staff, and eliminate efforts to implement electronic permitting).

Analysis of the fee alternatives that could be implemented by regulation showed that none of them produced significant reductions in fees. Analysis of changing the way permit administration fees are calculated demonstrated that the current (relatively new) fee structure may set those fees below what is necessary to cover the costs of permit administration. Among the cost cutting measures, although discussion of reducing staff and eliminating some permitee assistance was brief, those two approached did not appear workable. The *report* advocates continuing both the QMS initiative and program technology efforts, based on the reasons those efforts were begun. However, it does not assess the degree to which eliminating those costs has the potential to reduce emissions fees. Such an analysis might be helpful.

To summarize this section or our review, the methodology was applied consistently, and where data were not available, reasonable assumptions were developed. Cost increases from historical levels were all supported by either a description of additional tasks to be performed or of other factors (such as inflation) that push costs upward.

4. Were the conclusions reached justified by the analysis?

The large fee increases called for in the *report* arise from the confluence of several factors:

- Escalating costs of personnel: The general inflation rate of 2.9% is not high, but it is combined with 5% per year increases to the personnel component for PERS contributions. Together, these two factors increase projected costs by over 25% between FY06 and FY10.
- Declining emissions: Compared with Title 5 assessable emissions in FY03 (the last time emission fees were adjusted) projected FY07 emissions are 25% lower. So rising costs must be allocated across fewer tons. It should be noted that if a particular entity is generating fewer emissions, their total bill (= fee per ton x number of tons) might stay relatively flat with respect to this factor.
- Initiatives undertaken to improve service cost money: Two of the cost-saving cuts that the Workgroup asked to be considered were initiatives that emerged from stakeholder input. The Quality Management System effort was undertaken to improve service and has the potential to reduce costs in the long run, although only the increased costs of implementation are immediately evident. Likewise, the technology initiative has the potential to reduce costs incurred both by the Division and by the permitees themselves (through easier and faster permitting processes). But few if any of these savings will occur over the next few years.

The *report* concludes by presenting several options for implementing the increased fees, with a brief discussion of the pros and cons of each. The preferred option is annually adjusted rates rather than a fixed average rate for several years. In addition the *report* authors recommend that the schedules for revising permit administration and emissions fees should be the same, so that both can be considered at the same time; Finally, the *report* authors recommend continuing consideration of (1) the adequacy of the 149% personnel rate required by statute for calculating permit administration fees; (2) changing permit renewal schedules so the permit renewal workload becomes more even across years; (3) continuing to explore other structures for Title 1 fees; and (4) increasing general fund levels to cover expected program costs not covered by fees. All of these recommendations are well-supported by the analyses presented in the *report*.

The *report* thoroughly explains the available data, its limitations, and how it was used to develop the recommended emission fee levels. Further development of AirTools, primarily intended as a tool for managing the program, should also help ensure fewer gaps in the historical data in future reports. Better coordinating Title 5 and Title 1 fee setting should not only save time and money by simplifying reporting, it should allow for the two fees to better reflect actual costs incurred. Finally, while the recommendation for additional general funding could be seen as beyond the scope of emission fee-setting, the *report* shows that activities undertaken by the Division, not related to emission fee-generating activities (Title 5 or Title 1), cost more than the amount covered by current general funding.