

prohibit discharges to freshwaters of Texas and Louisiana. This option reflects current practice. Option 2 would require the same limitations as the preferred option for produced water. This option would require for BAT that discharges of treatment, workover and completion fluids would be prohibited in all coastal areas except Cook Inlet. In Cook Inlet, these discharges would be required to meet a daily maximum oil and grease limitation of 42 mg/l and a 30 day average of 29 mg/l. Option 2 would require zero discharged of these fluids everywhere for NSPS.

The total cost of compliance with these selected BAT options is \$30.9 million to \$35.4 million per year in 1992's (or \$33.5 million to \$38.4 million in 1994's). Additionally, compliance with the BAT options would result in up to approximately \$9.5 million in lost oil and gas revenues, taxes and royalties annually.<sup>3</sup>

NSPS requirements for produced water is zero discharge (only the Gulf is expected to have new sources). The options being co-proposed for NSPS for drilling fluids and cuttings and treatment, workover and completion fluids are the same as those considered for BAT. Total compliance cost of NSPS for this proposal ranges from \$4.48 to approximately \$5 million annually in 1992 \$'s (or \$4.9 to \$5.4 million annually in 1994 \$'s). Additionally, compliance with the selected NSPS options could also result in roughly \$1 to 2 million in lost oil and gas revenues, royalties and taxes annually. Costs of NSPS for produced water are associated only with six new source production facilities per year projected in the Gulf region. No new sources are projected in Cook Inlet. For the six new production facilities constructed per year in the Gulf, costs of the produced water NSPS are estimated to be approximately \$4.48 million per year or \$38.4 million (present value) over a 15-year time frame.

Costs of NSPS for well treatment, workover and completion fluids are based on EPA projections that 45 new source wells would be discharging these fluids (without this rule) in the Gulf region. No new sources are projected in Cook Inlet. For the 45 new source wells in the Gulf region costs of the NSPS options for well treatment, workover

and completion fluids are estimated to range from \$0.00 to approximately \$0.52 million per year or \$0.00 to \$4.4 million (present value) over a 15-year time frame.

Because current practice for control of drilling fluids and drill cuttings in the Gulf region is zero discharge and no new sources are projected in Cook Inlet, no additional costs will be incurred due to NSPS for drilling fluids and drill cuttings.

Total compliance cost of all BAT and NSPS requirements ranges from \$35.34 million to \$40.36 million per year in 1992 \$'s (or \$38.3 million to \$43.8 million annually in 1994 \$'s). These compliance costs will also result in up to \$11.5 million in lost oil and gas revenues, royalties and taxes annually. Note that these costs are a small percentage of coastal revenues and operating costs (the direct costs of operating the business, i.e., not including general and administrative costs, depletion, depreciation, taxes, interest, etc.). Total revenues stemming from coastal operations among coastal firms (Texas, Louisiana, and Cook Inlet, Alaska, only) are estimated to be \$6.1 billion per year. Thus the total annual cost of the proposed Coastal Guidelines is estimated to be at most 0.7 percent of annual coastal revenues. The total coastal operating costs among coastal firms is estimated to be \$1.2 billion per year, thus annual compliance costs of this proposed rule are estimated to be up to 3.3 percent of total annual operating costs.

BAT production losses under the selected options are expected to total at most 40.2 million barrels of oil equivalent (BOE) over the lifetime of the wells and platforms as a result of the regulatory options (average postcompliance lifetime is 10 years in both the Gulf and Cook Inlet). In Cook Inlet, the production loss over the expected productive lifetime of the platforms is expected to be up to 12.4 million total BOE, which is 3.1 percent of the estimated lifetime production for the region. In the Gulf, the lifetime production loss is expected to be up to 27.9 million total BOE, which is 0.9 percent of a high estimate of lifetime production and 1.7 percent of a low estimate of lifetime production in the Gulf. For the two regions combined, the maximum 40.2 million BOE loss (or 17.9 million BOE in present value) in production is 1.1 percent to 2.0 percent of total lifetime production. These losses are associated with declines in the net present value of producer income totalling up to \$144.5 million in the Gulf and \$15.9 million in Cook Inlet for a total of \$160.4 million or 0.7 to 1.5

percent of total net present value of baseline producer income in the two regions.<sup>4</sup> These losses result from both immediate shut in of wells or platforms and/or shortened economic lifetimes. A total of up to 111 Gulf wells (2.4 percent of all current coastal Gulf wells) and no Cook Inlet platforms are considered likely to shut in at once under the proposed options. These shut-in wells tend to be relatively low-producing or marginal wells as can be seen from the relatively lower percentage of production affected as compared to a higher percentage of wells.

A maximum of 12 firms owning and/or operating Gulf Coastal wells might possibly fail as a result of the proposed regulatory options. Data were not available to rule out the possibility of firm failure, so they were counted as potential firm failures, thus the actual number of firm failures could be as few as none. No failures are predicted for operators in Cook Inlet. It is estimated that the majority (72 percent) of firms in the Gulf Coastal region by 1996 will not discharge produced water. Thus, most firms will incur no compliance costs. The Gulf Coastal firms, therefore, are potentially expected to face average (median) declines in equity or working capital of 0 percent. Discharging firms are potentially expected to face average (median) declines in equity and working capital of 0.37 percent and 2.63 percent, respectively.

The options potentially could result in a present value loss of up to \$91 million in federal and state income tax revenues over an average of 10 years, or up to \$13.6 million, on average, annually (primarily federal taxes). This loss is only 11 percent of income taxes from discharging wells and platforms alone. Losses to state revenues due to a potential loss of severance taxes total \$10.8 million over 10 years, or \$1.6 million, on average, annually. This loss is only 3.8 percent of severance taxes from discharging wells and platforms alone. The states could also potentially lose royalties totaling at most, an estimated present value of \$39.4 million over 10 years, or \$5.9 million, on average, annually, which is only 5.8 percent of royalties collected from discharging wells and platforms alone. These effects are negligible compared to federal and state revenues and royalties collected.

The proposed rule is not expected to affect energy prices, international trade, or inflation, and would have a minimal impact on national-level employment. Primary employment losses would be

<sup>3</sup>The industry will not experience the entire impact of these costs because depreciation allowances and increased costs of production stemming from these compliance costs will serve to reduce taxable income. Thus a portion of these costs will be borne by federal and state governments rather than industry or individual firm owners. This portion is known as industry's "tax shield." This impact to governments is, however, noted in the analyses discussed below.

<sup>4</sup>The losses of \$160.4 million included costs of technology and resulting production losses.