Modeling Results for Seven Production Units and Alaska's North Slope Total

Prudhoe Bay

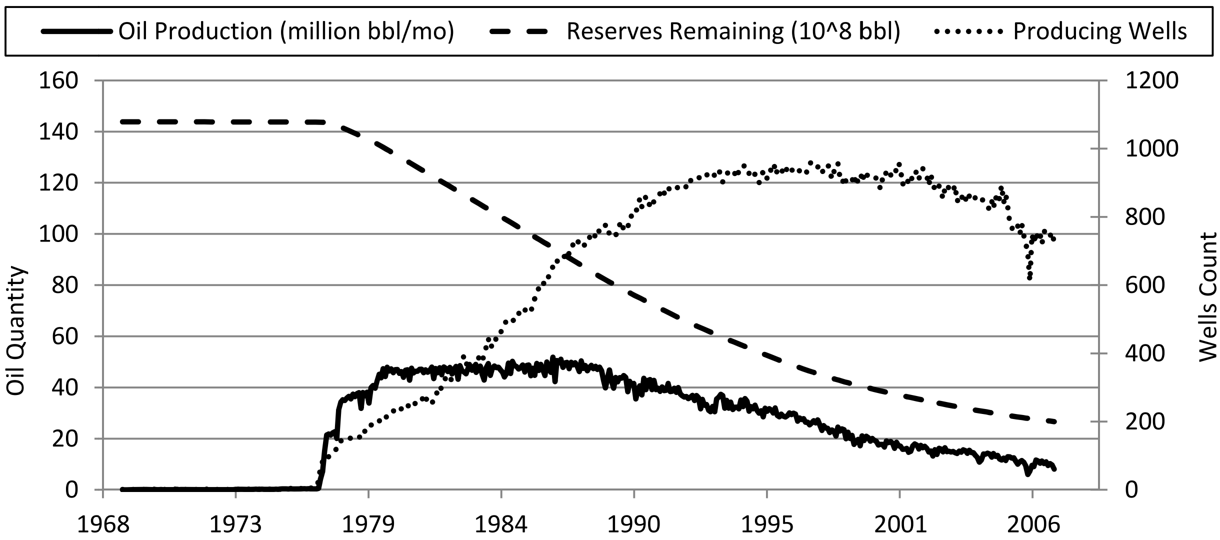

Figure 3: The historical number of producing wells, production rate, and reserves remaining for Prudhoe Bay over time.

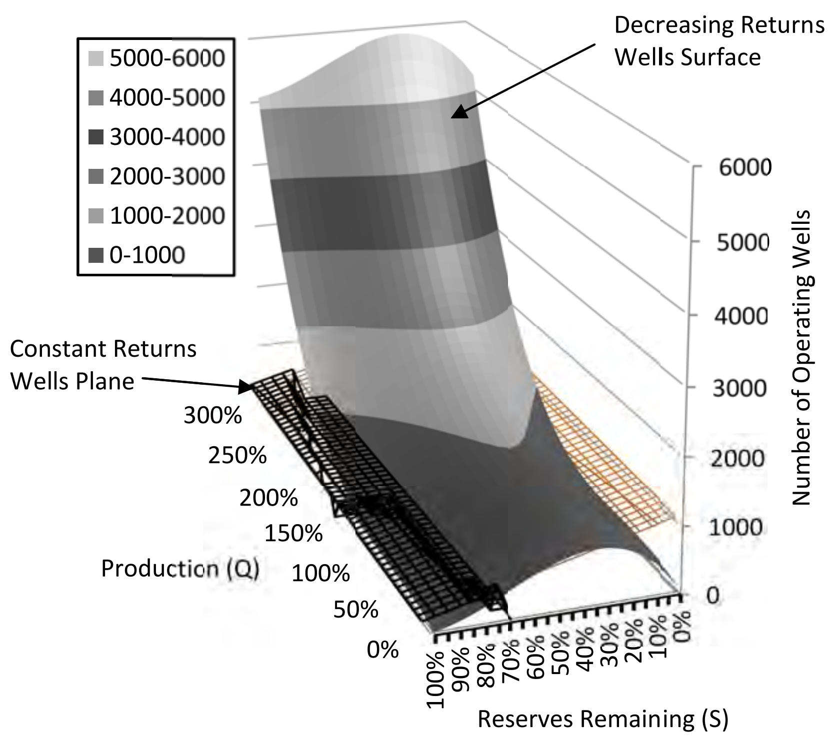

Figure 5: Prudhoe Bay wells as a function of production (Q) and reserves remaining (S), with the constant returns plane and the decreasing returns surface shown. The horizontal and depth axes are given in percentage terms, from zero to 100% of original technically recoverable reserves and from 0% to 300% of historical maximum production rate.

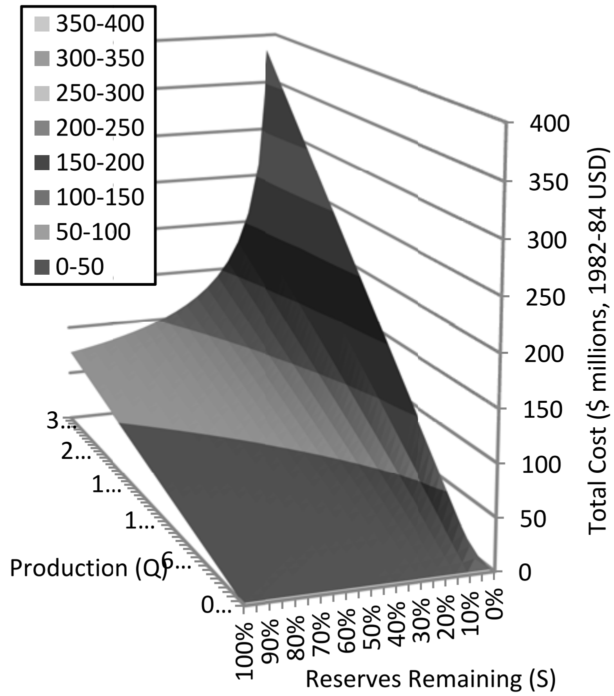

Figure 4: The base average total cost of production from Prudhoe Bay for combinations of reserves remaining and production rate (given in percentage terms, from zero to 100 percent of original technically recoverable reserves in the field and from 0 to 300 percent of historical maximum production rate).

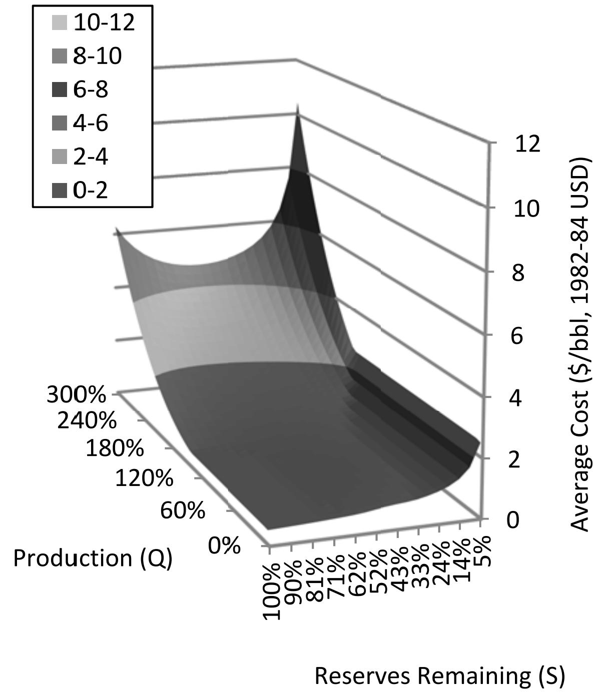

Figure 6: The composite cost function for Prudhoe Bay in 2003.

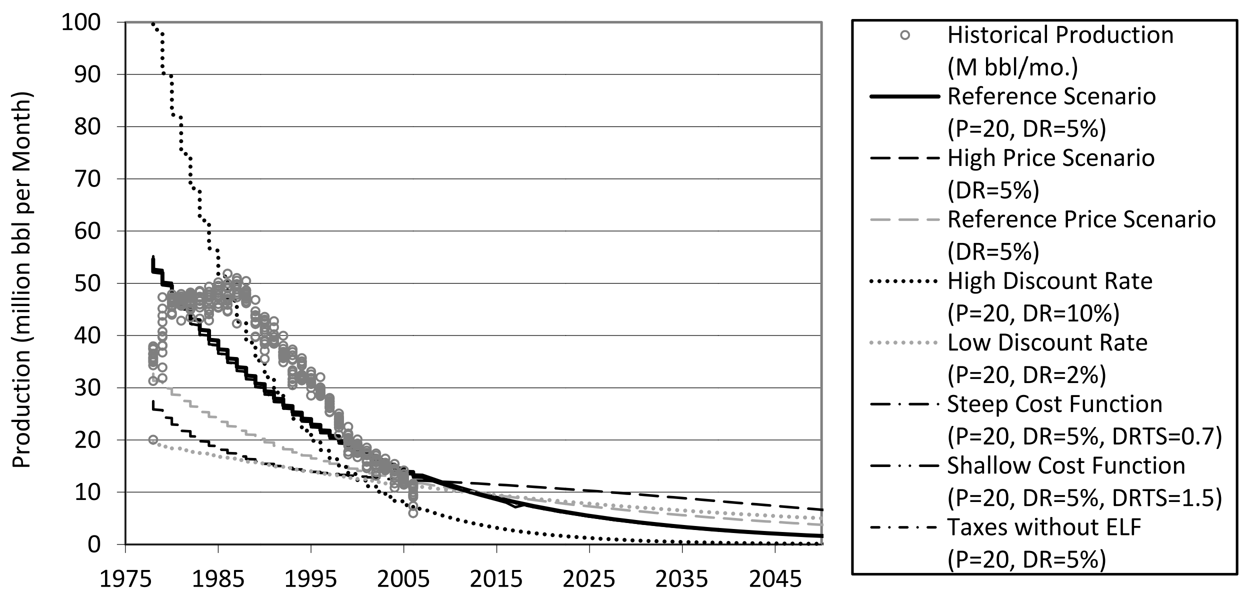

Figure 9: Sensitivity analysis for the un-calibrated model of Prudhoe Bay (i.e., unconstrained for initial production rate and without adjustment costs).

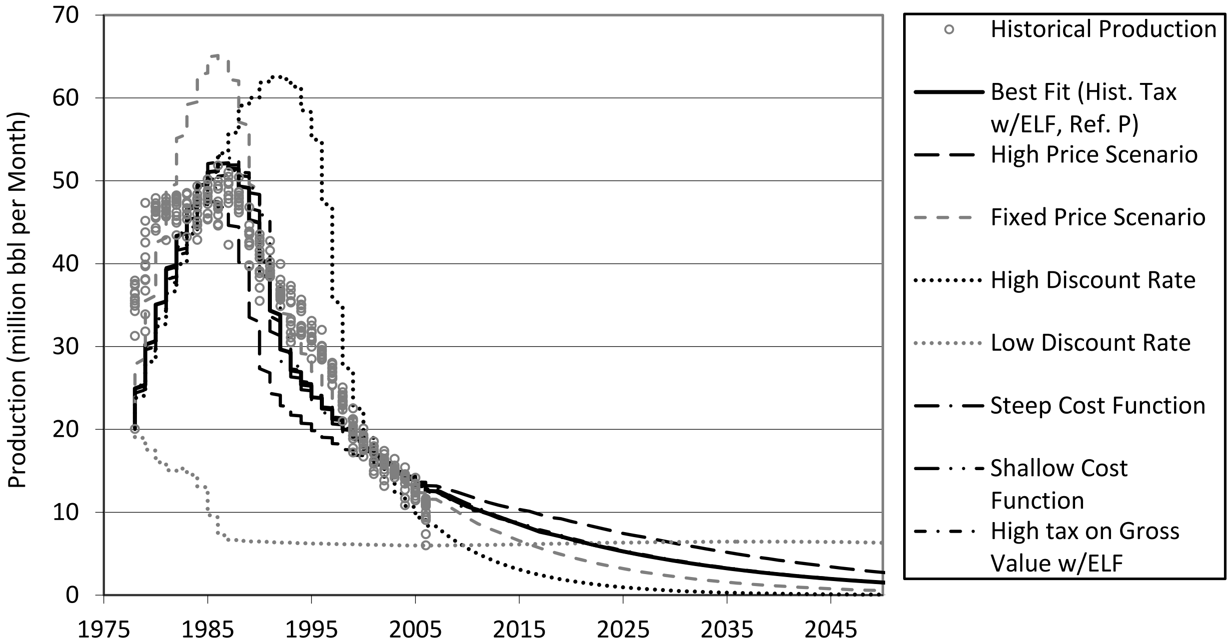

Figure 10: Sensitivity analysis of the calibrated model for Prudhoe Bay.

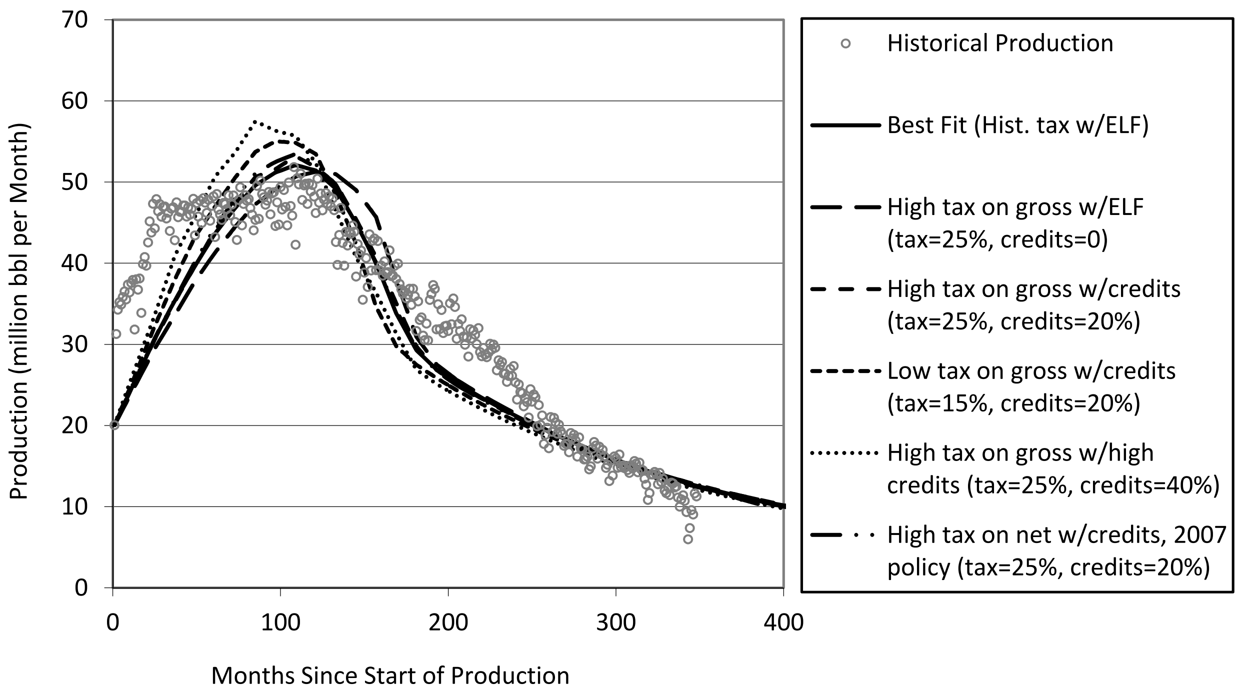

Figure 11: Historical Prudhoe Bay oil production data, modeled economically optimal production with historical tax policy (Best Fit), and modeled economically optimal production under several tax policy scenarios.

Kuparuk River

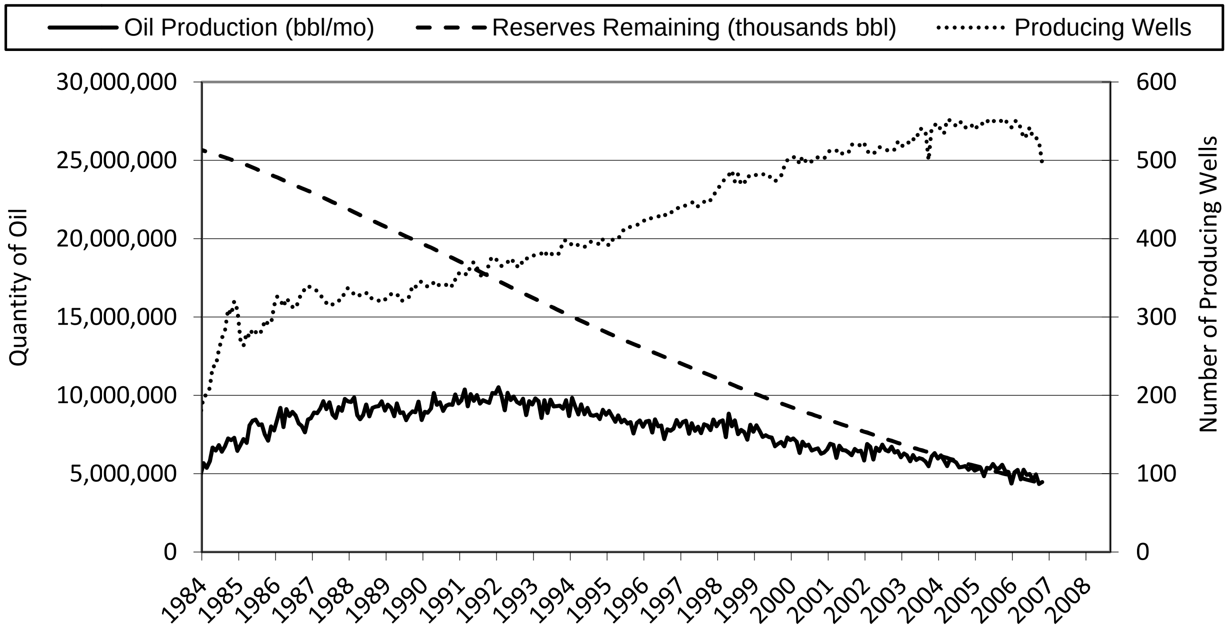

Figure 3: The historical number of producing wells, production rate, and reserves remaining for Kuparuk River over time.

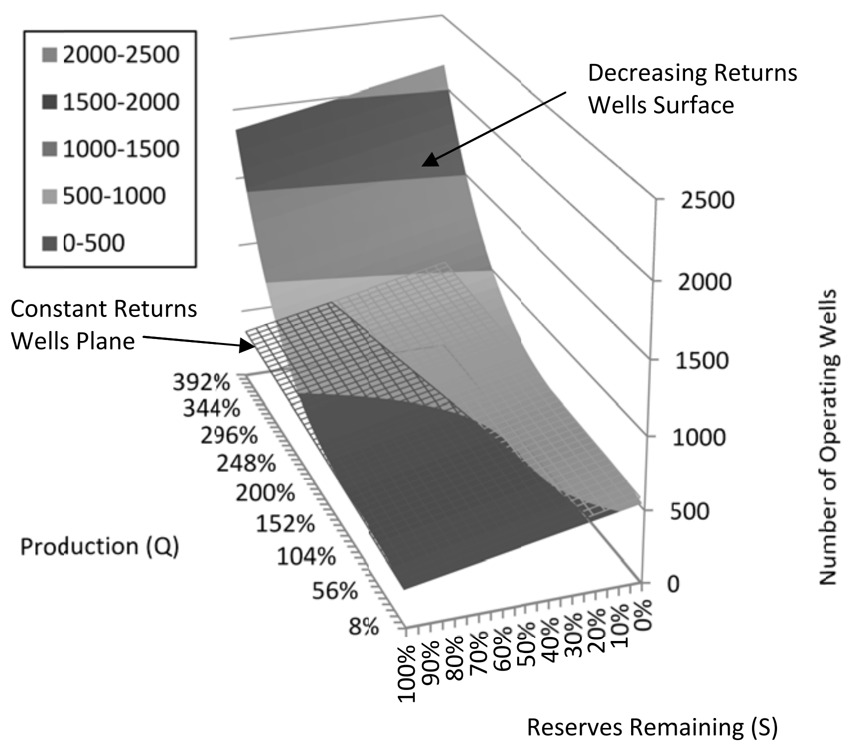

Figure 5: Kuparuk wells as a function of production (Q) and reserves remaining (S), with the constant returns plane and the decreasing returns surface shown. The horizontal and depth axes are given in percentage terms, from zero to 100% of original technically recoverable reserves and from 0% to 400% of historical maximum production rate.

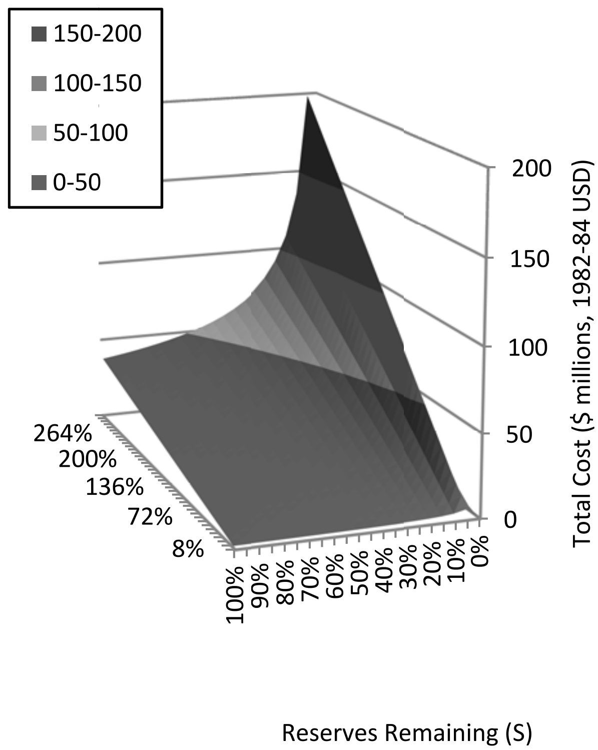

Figure 4: The base average total cost of production from Kuparuk for combinations of reserves remaining and production rate (given in percentage terms, from zero to 100 percent of original technically recoverable reserves in the field and from 0 to 300 percent of historical maximum production rate).

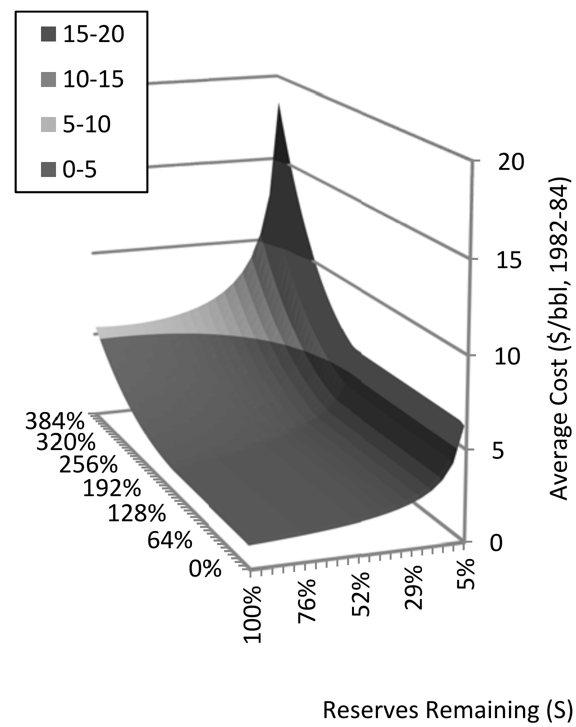

Figure 6: The composite cost function for Kuparuk in 2003.

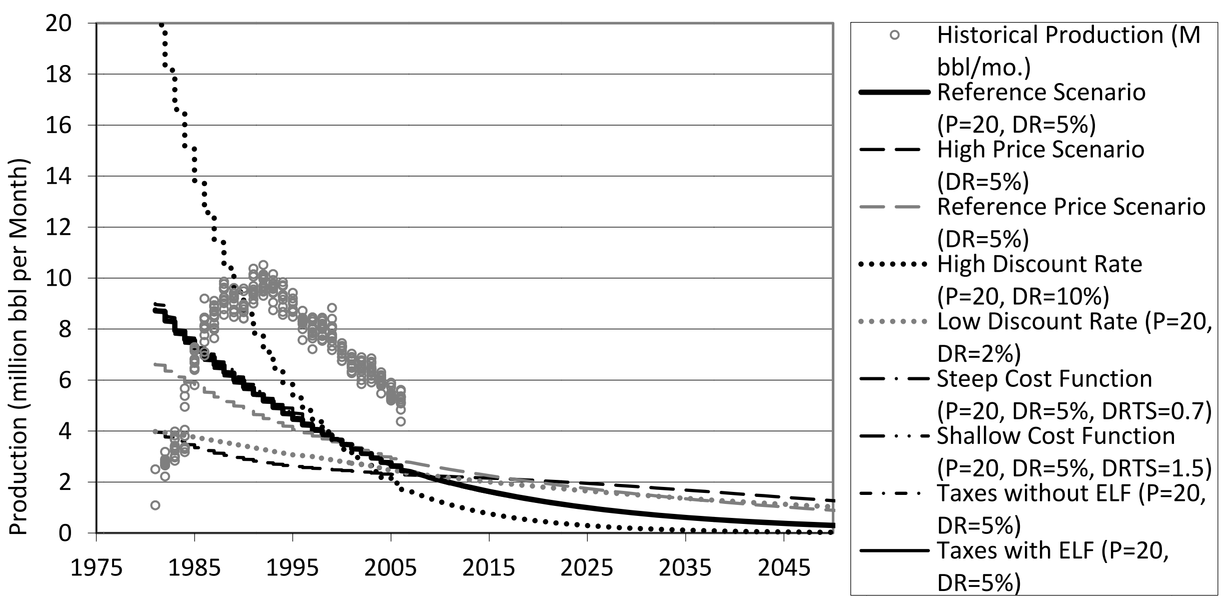

Figure 9: Sensitivity analysis for the un-calibrated model of Kuparuk (i.e., unconstrained for initial production rate and without adjustment costs).

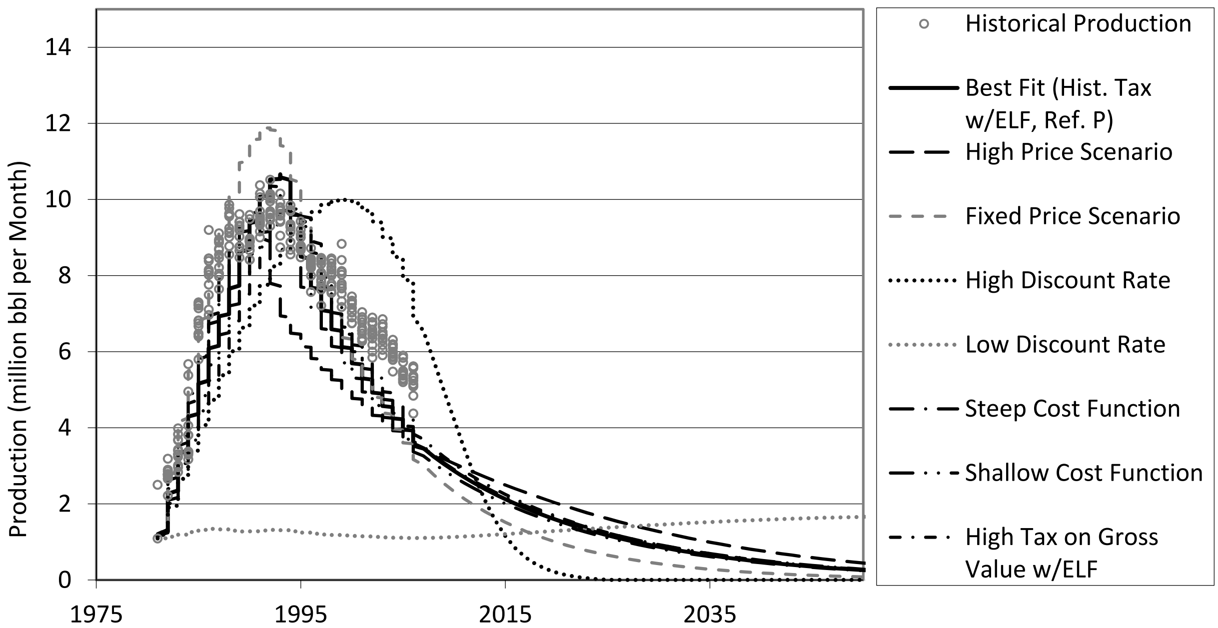

Figure 10: Sensitivity analysis of the calibrated model for Kuparuk.

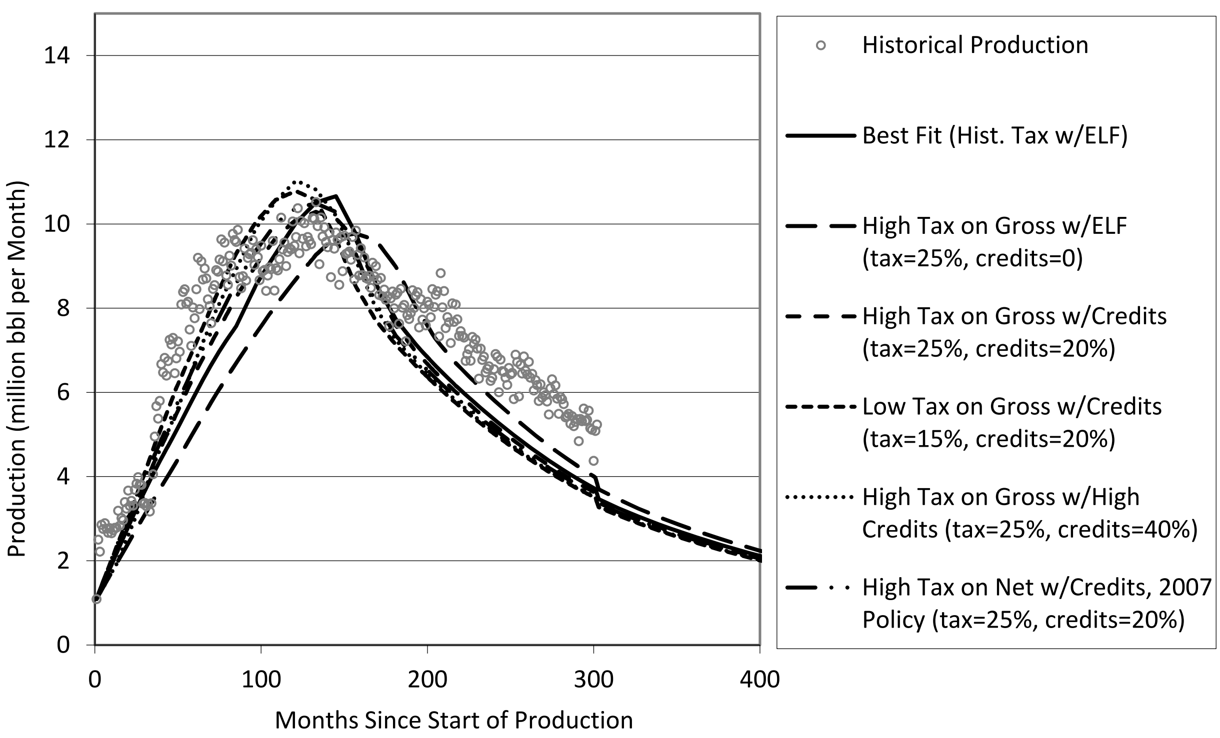

Figure 11: Historical Kuparuk oil production data, modeled economically optimal production with historical tax policy (Best Fit), and modeled economically optimal production under several tax policy scenarios.

Milne Point

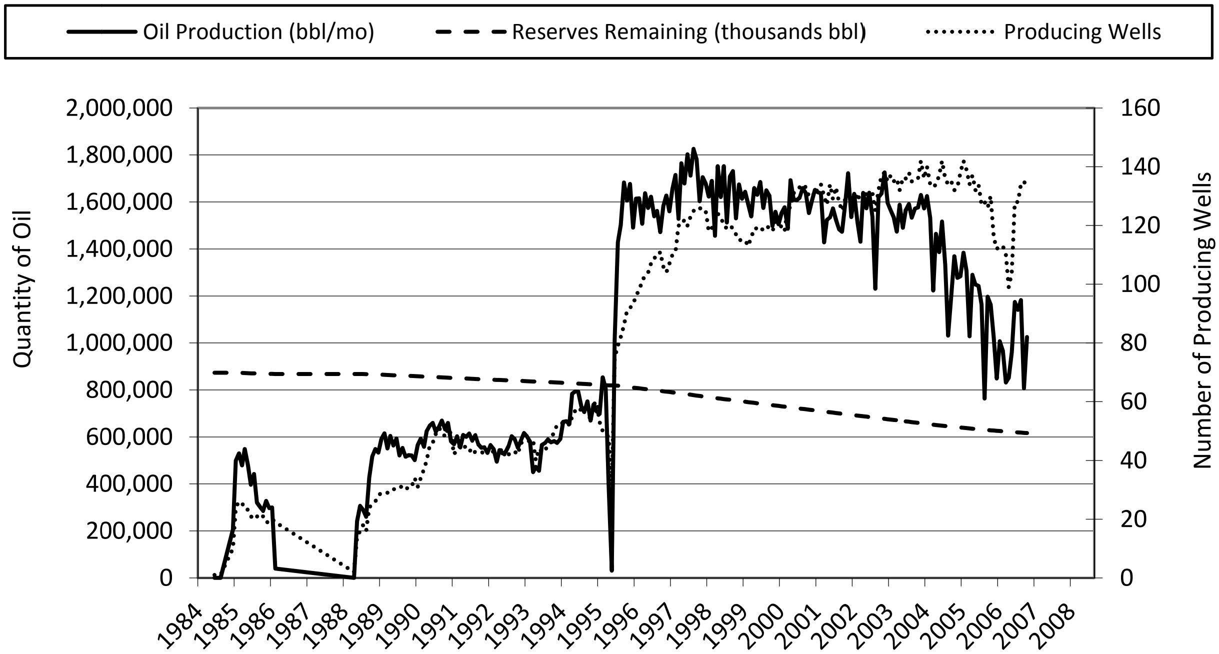

Figure 3: The historical number of producing wells, production rate, and reserves remaining for Milne Point over time.

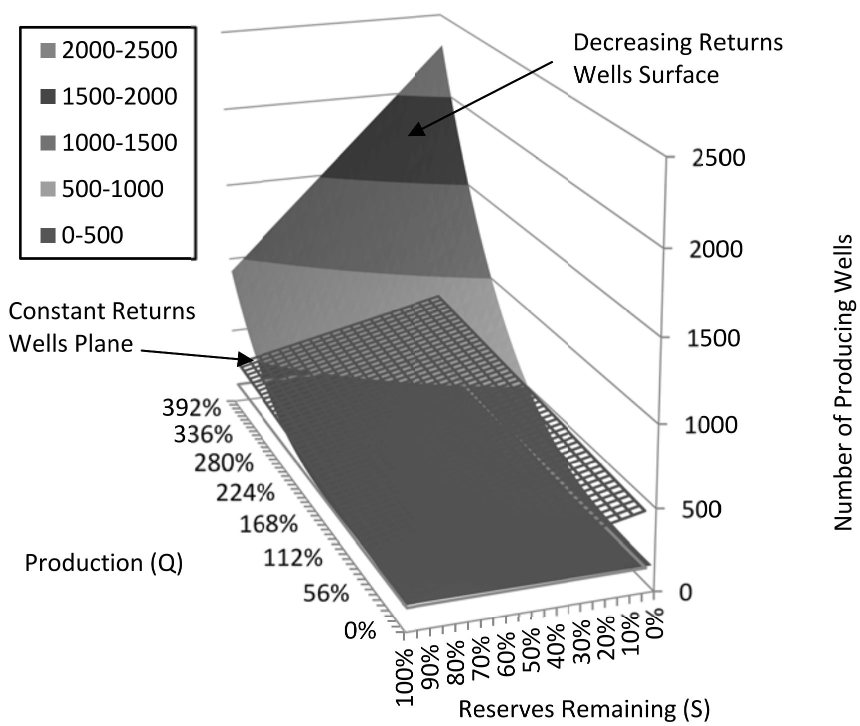

Figure 5: Milne Point wells as a function of production (Q) and reserves remaining (S), with the constant returns plane and the decreasing returns surface shown. The horizontal and depth axes are given in percentage terms, from zero to 100% of original technically recoverable reserves and from 0% to 400% of historical maximum production rate.

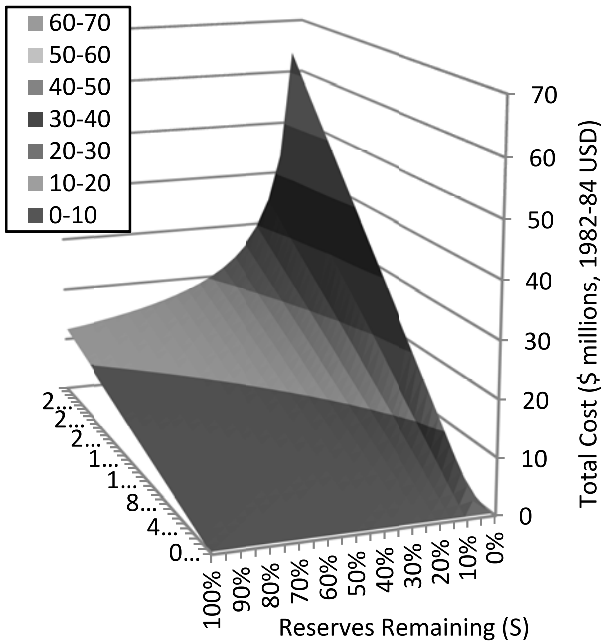

Figure 4: The base average total cost of production from Milne Point for combinations of reserves remaining and production rate (given in percentage terms, from zero to 100 percent of original technically recoverable reserves in the field and from 0 to 300 percent of historical maximum production rate).

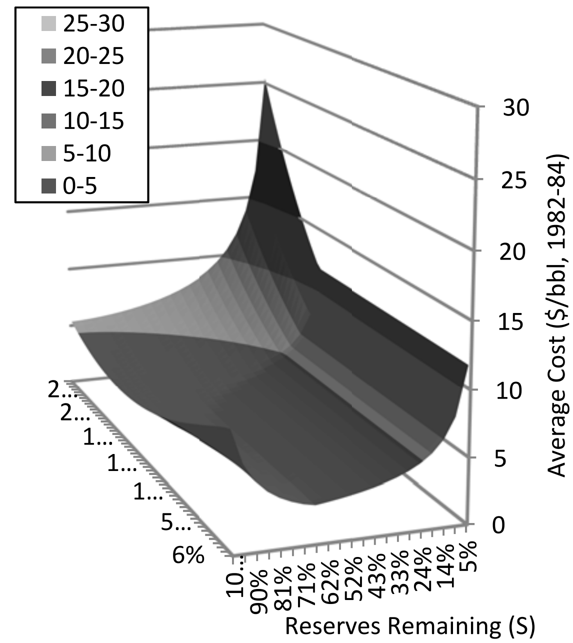

Figure 6: The composite cost function for Milne Point in 2003.

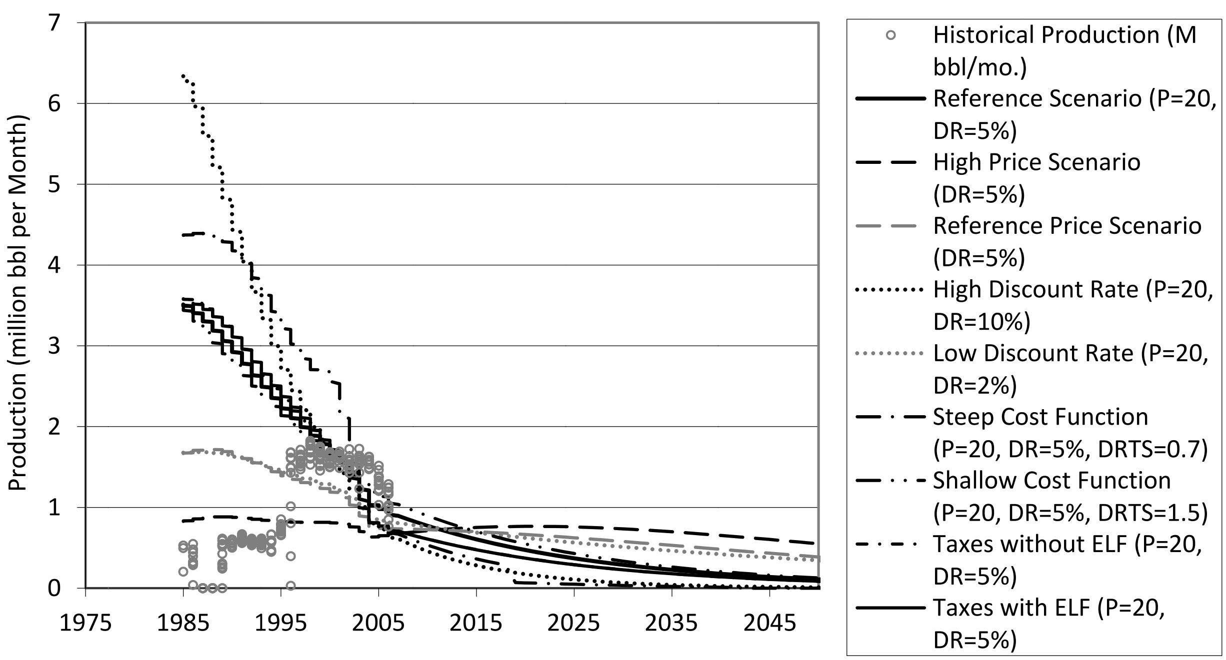

Figure 9: Sensitivity analysis for the un-calibrated model of Milne Point (i.e., unconstrained for initial production rate and without adjustment costs).

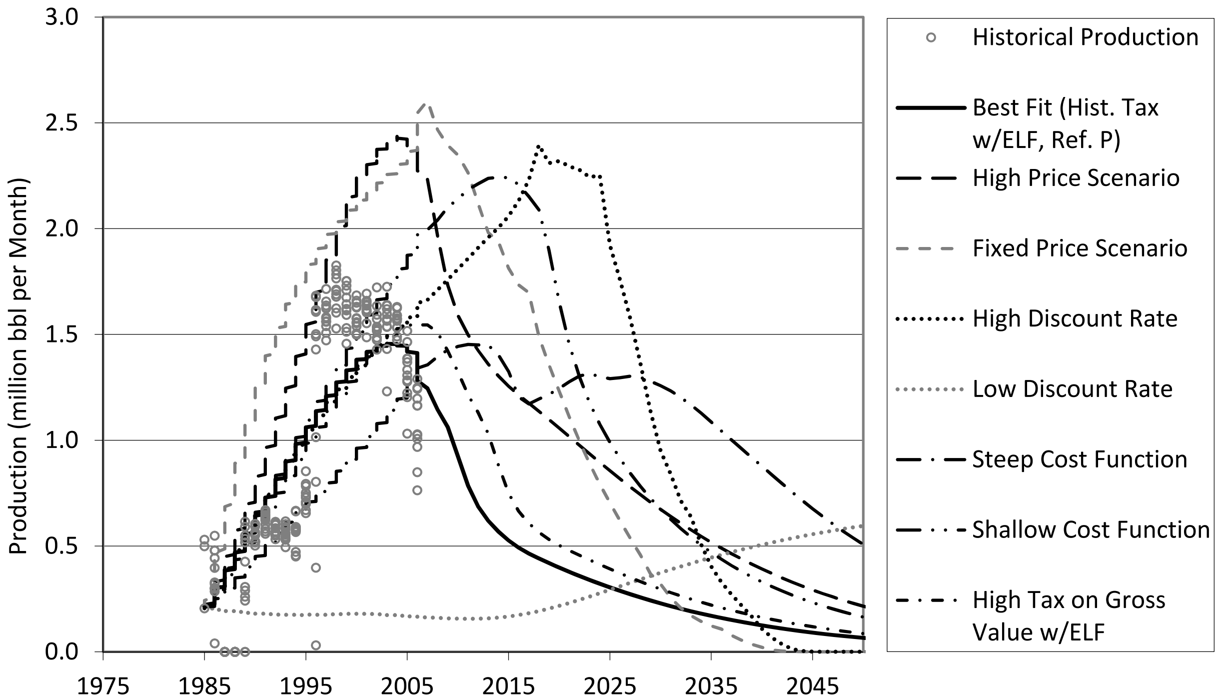

Figure 10: Sensitivity analysis of the calibrated model for Milne Point.

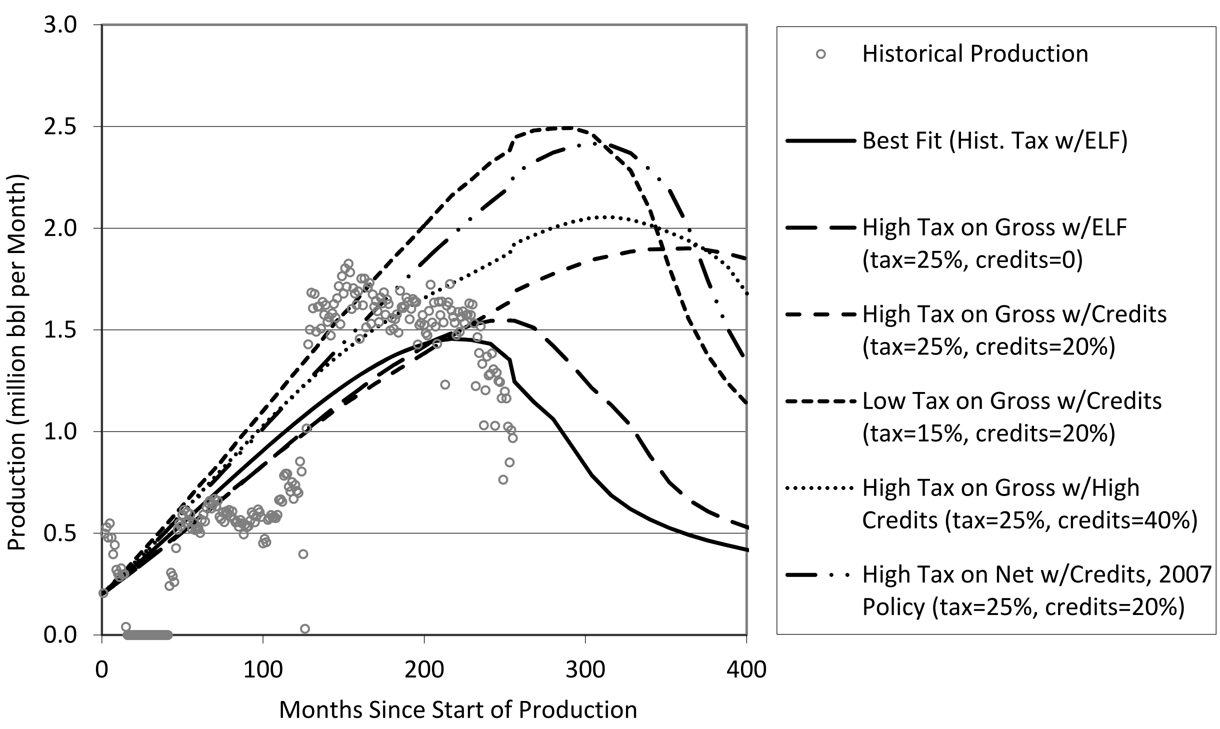

Figure 11: Historical Milne Point oil production data, modeled economically optimal production with historical tax policy (Best Fit), and modeled economically optimal production under several tax policy scenarios.

Endicott

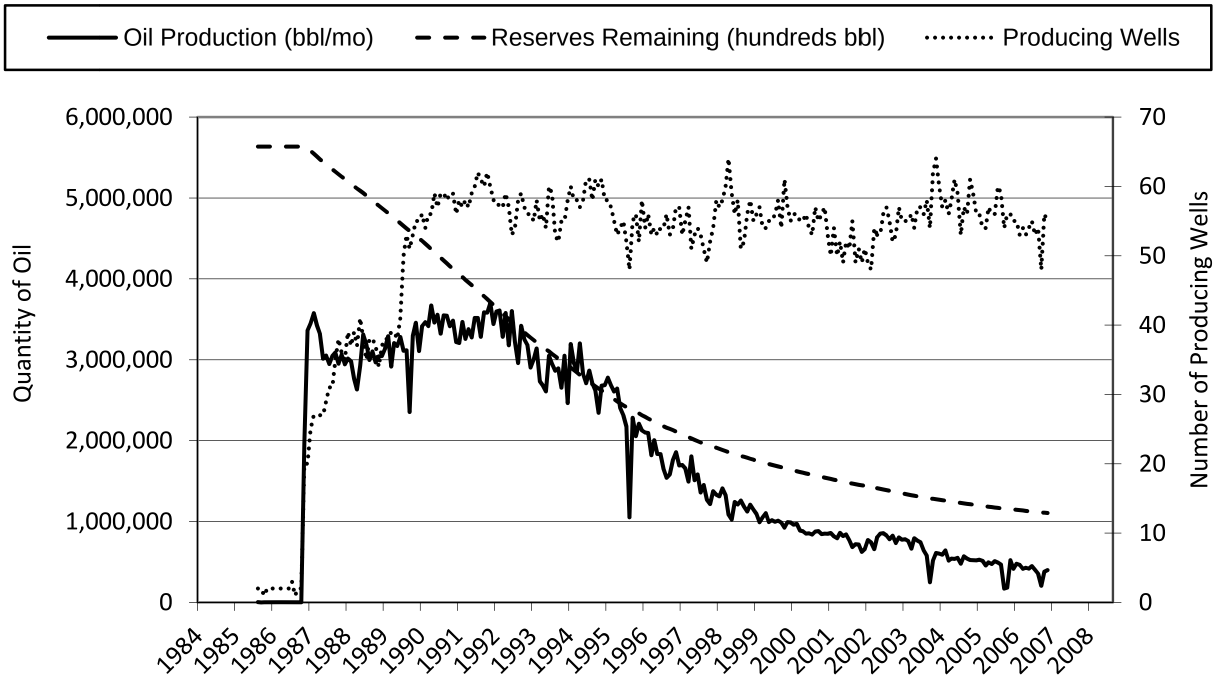

Figure 3: The historical number of producing wells, production rate, and reserves remaining for Endicott over time.

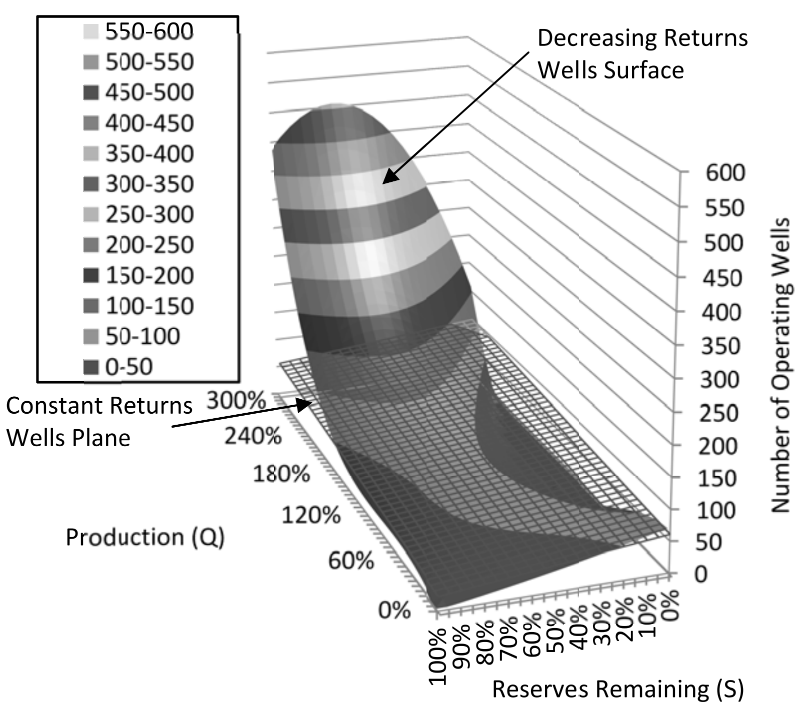

Figure 5: Endicott wells as a function of production (Q) and reserves remaining (S), with the constant returns plane and the decreasing returns surface shown. The horizontal and depth axes are given in percentage terms, from zero to 100% of original technically recoverable reserves and from 0% to 300% of historical maximum production rate.

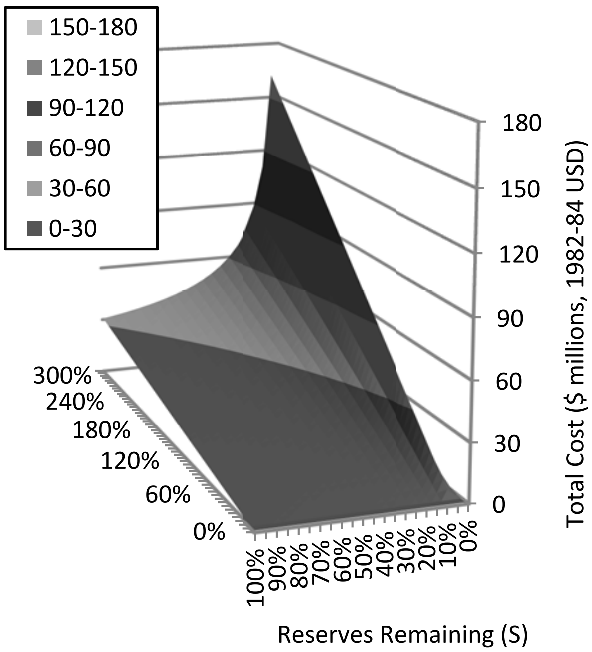

Figure 4: The base average total cost of production from Endicott for combinations of reserves remaining and production rate (given in percentage terms, from zero to 100 percent of original technically recoverable reserves in the field and from 0 to 300 percent of historical maximum production rate).

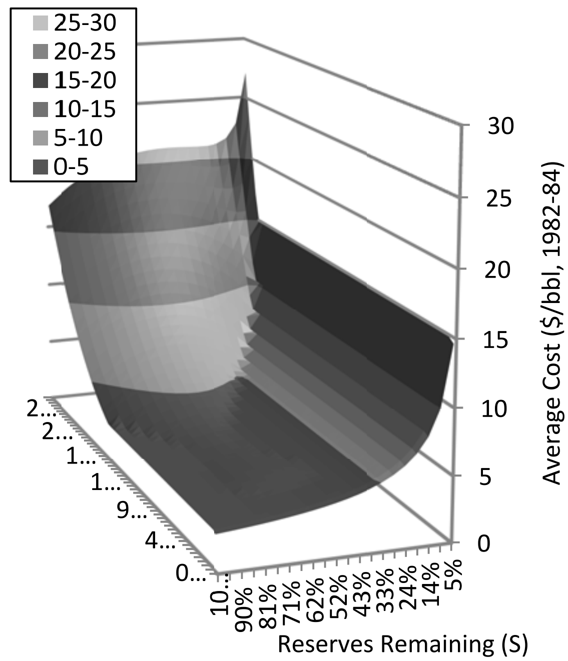

Figure 6: The composite cost function for Endicott in 2003.

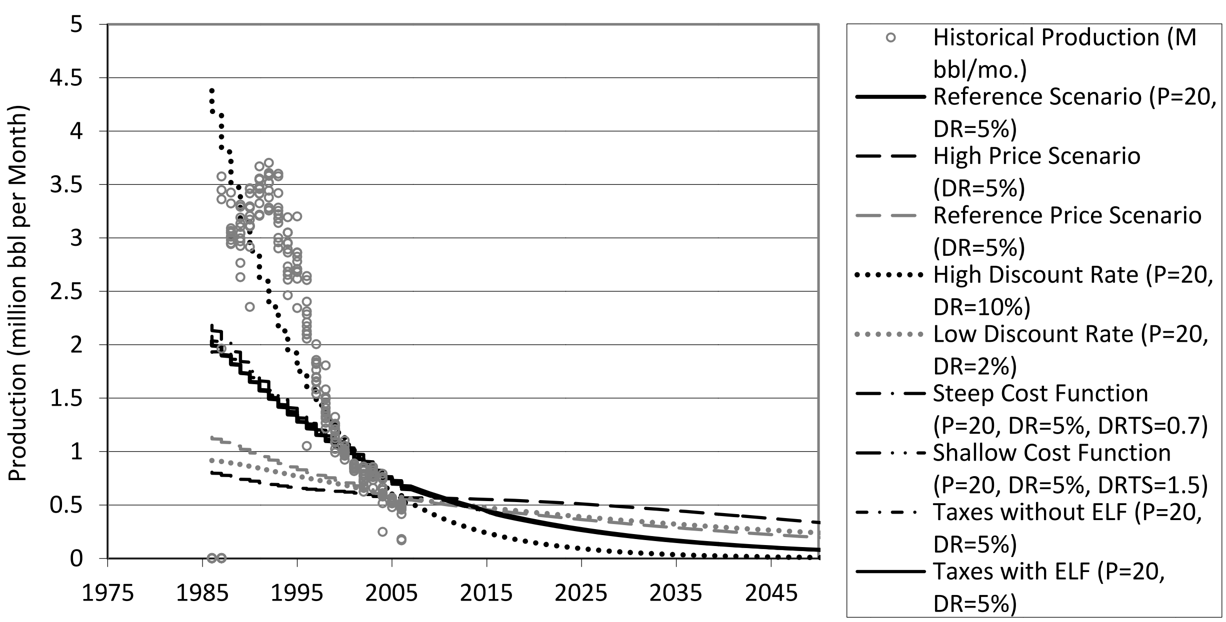

Figure 9: Sensitivity analysis for the un-calibrated model of Endicott (i.e., unconstrained for initial production rate and without adjustment costs).

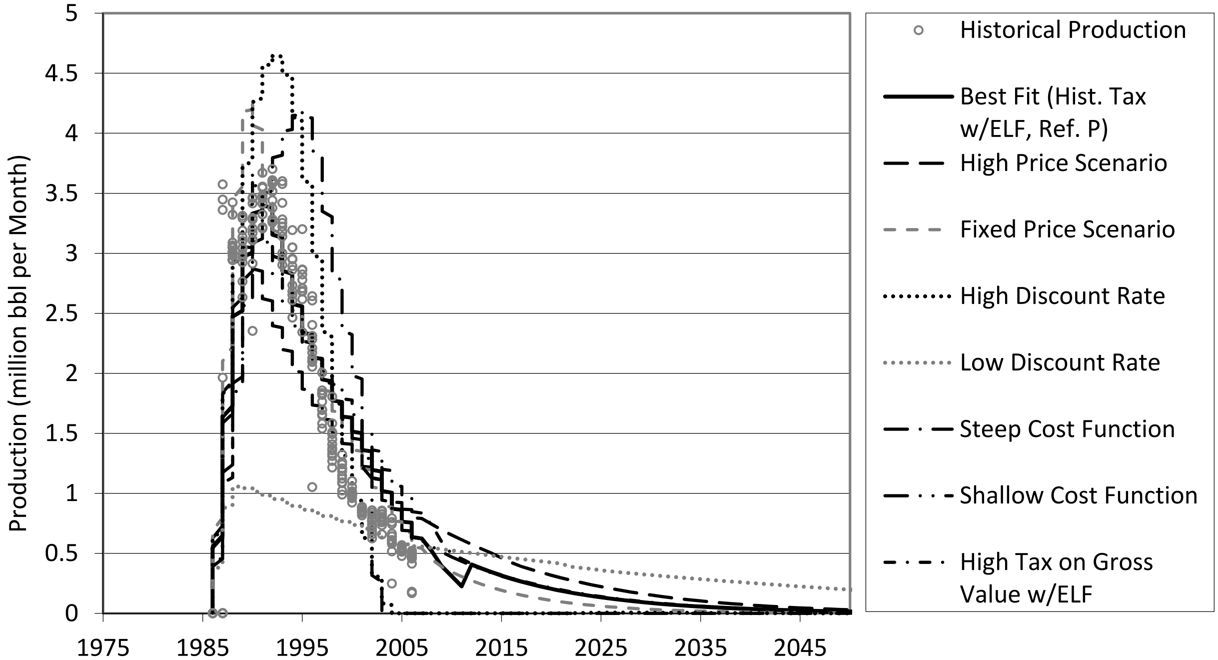

Figure 10: Sensitivity analysis of the calibrated model for Endicott.

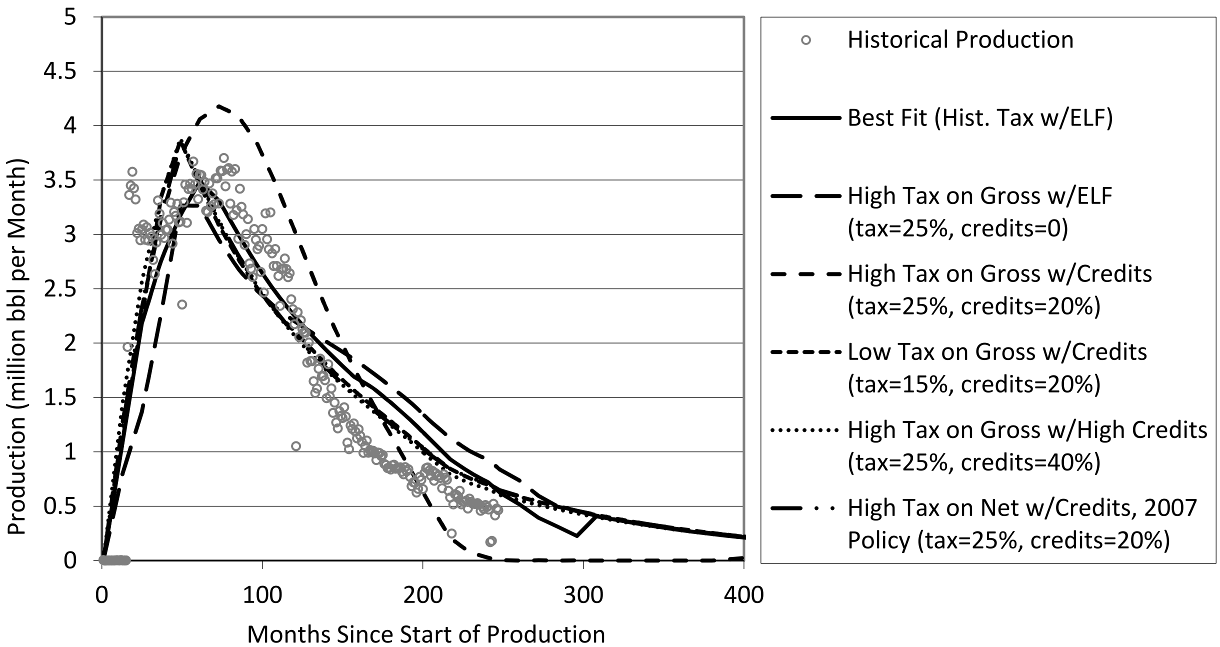

Figure 11: Historical Endicott oil production data, modeled economically optimal production with historical tax policy (Best Fit), and modeled economically optimal production under several tax policy scenarios.

Colville River

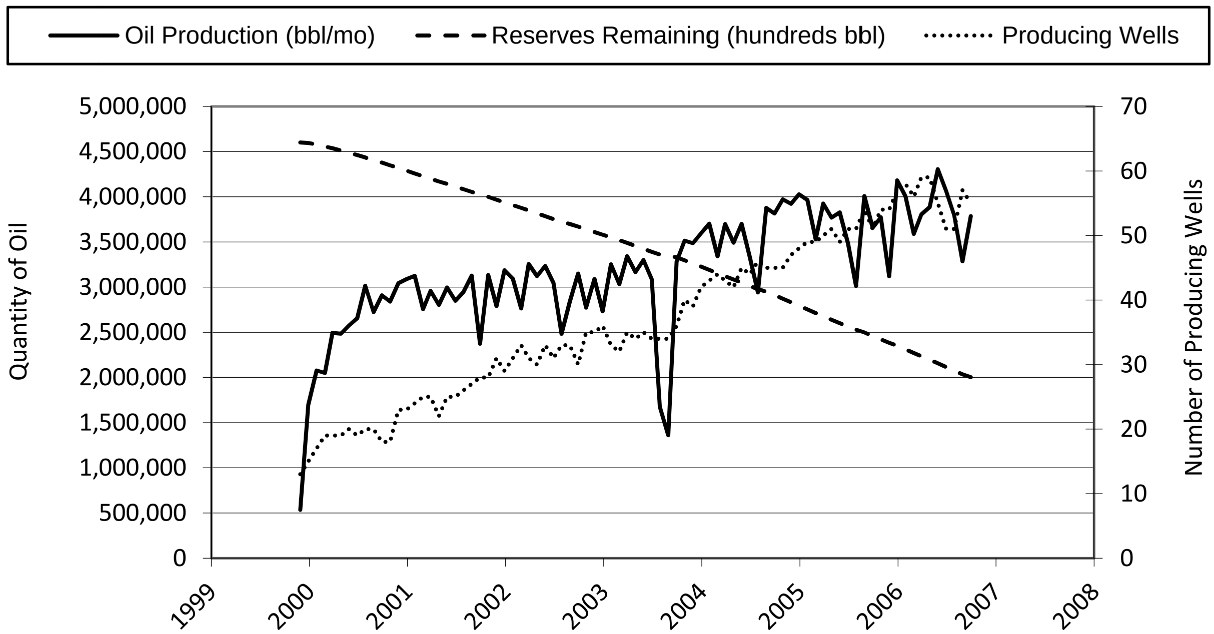

Figure 3: The historical number of producing wells, production rate, and reserves remaining for Colville River over time.

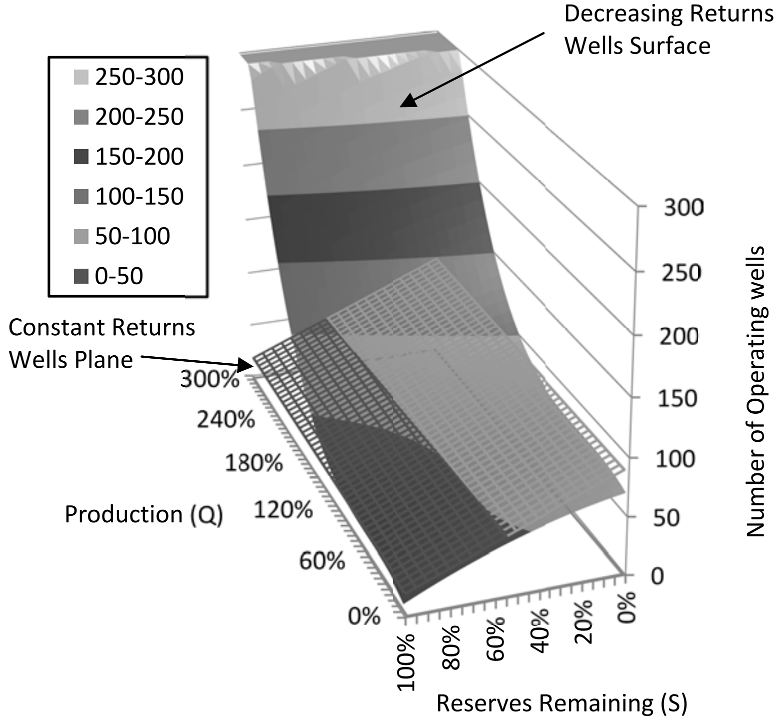

Figure 5: Colville River wells as a function of production (Q) and reserves remaining (S), with the constant returns plane and the decreasing returns surface shown. The horizontal and depth axes are given in percentage terms, from zero to 100% of original technically recoverable reserves and from 0% to 300% of historical maximum production rate.

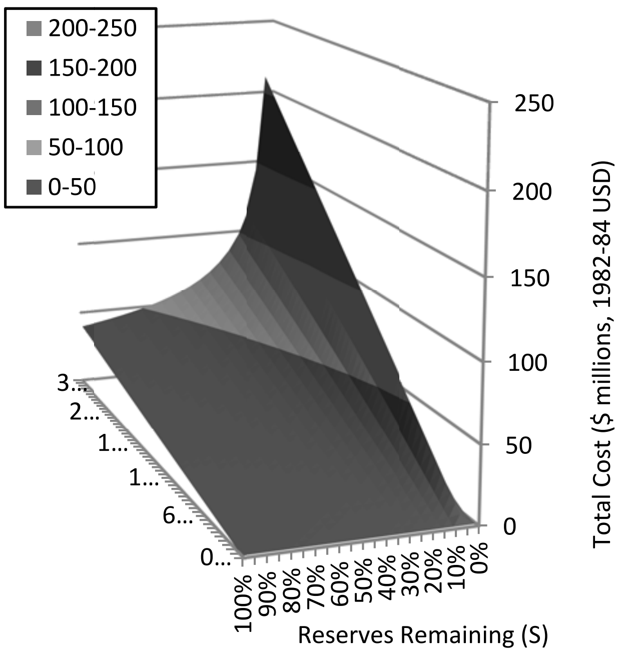

Figure 4: The base average total cost of production from Colville River for combinations of reserves remaining and production rate (given in percentage terms, from zero to 100 percent of original technically recoverable reserves in the field and from 0 to 300 percent of historical maximum production rate).

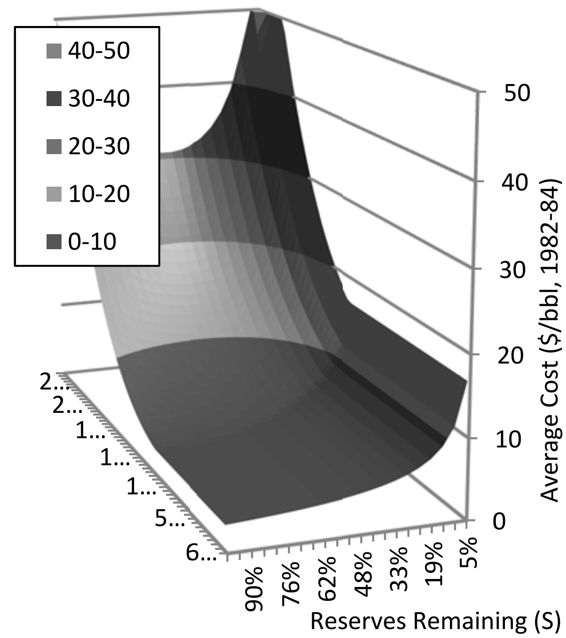

Figure 6: The composite cost function for Colville River in 2003.

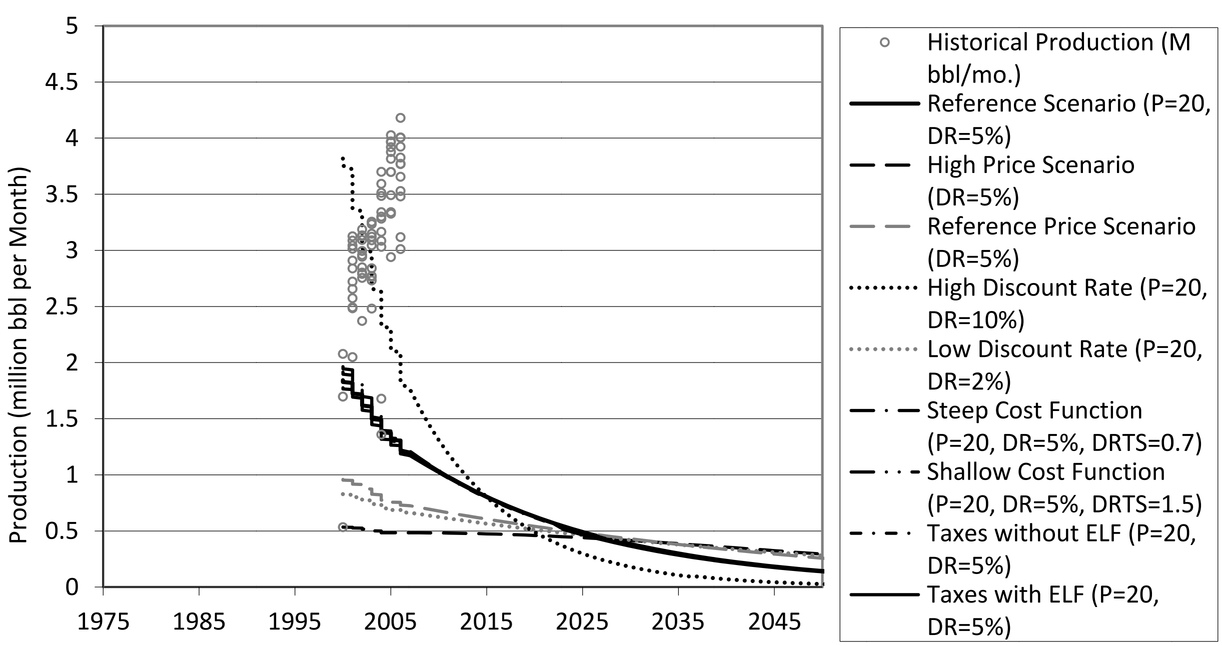

Figure 9: Sensitivity analysis for the un-calibrated model of Colville River (i.e., unconstrained for initial production rate and without adjustment costs).

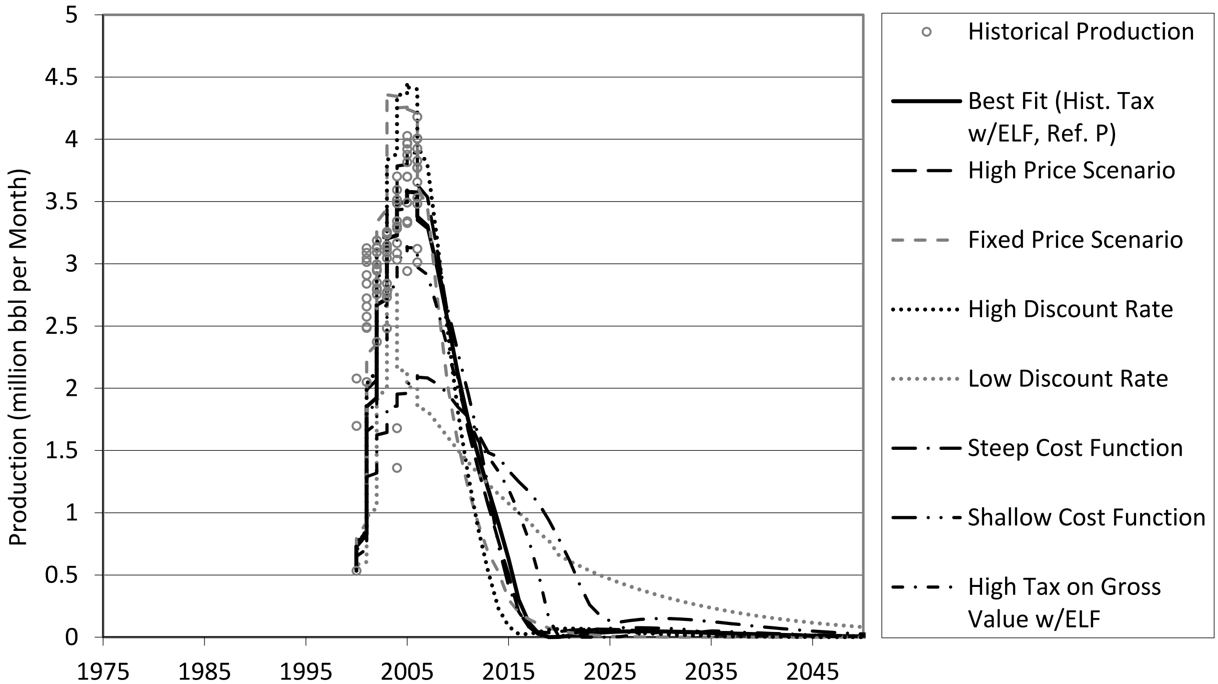

Figure 10: Sensitivity analysis of the calibrated model for Colville River.

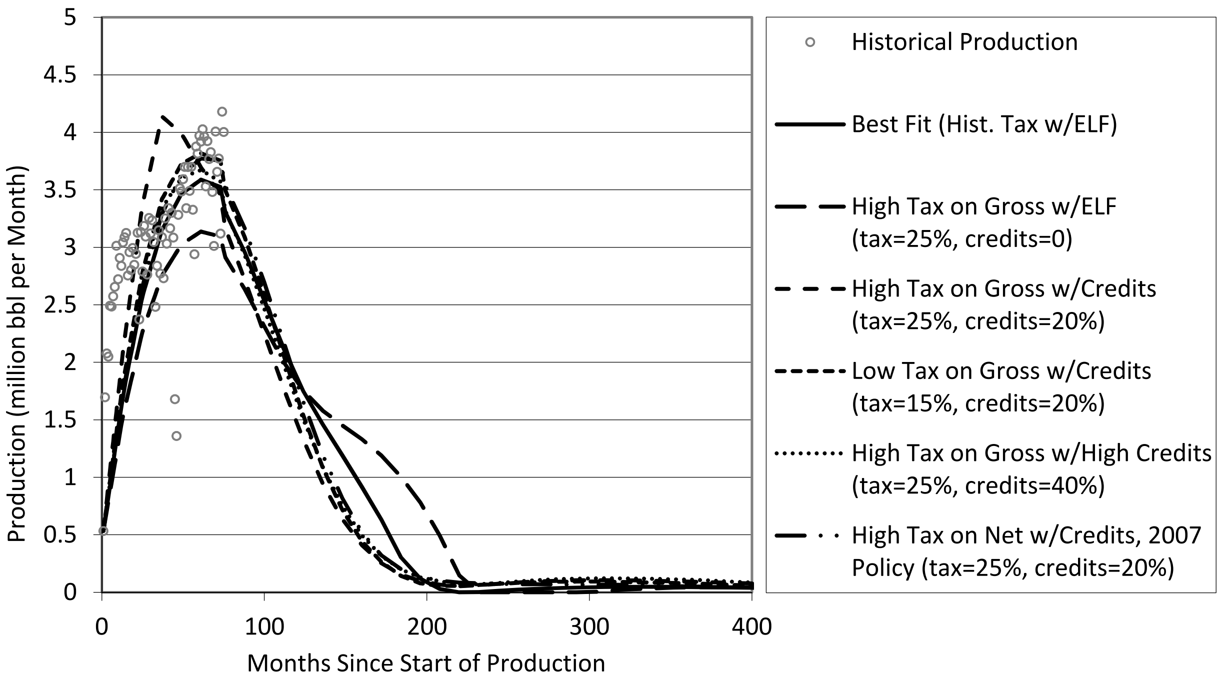

Figure 11: Historical Colville River oil production data, modeled economically optimal production with historical tax policy (Best Fit), and modeled economically optimal production under several tax policy scenarios.

Northstar

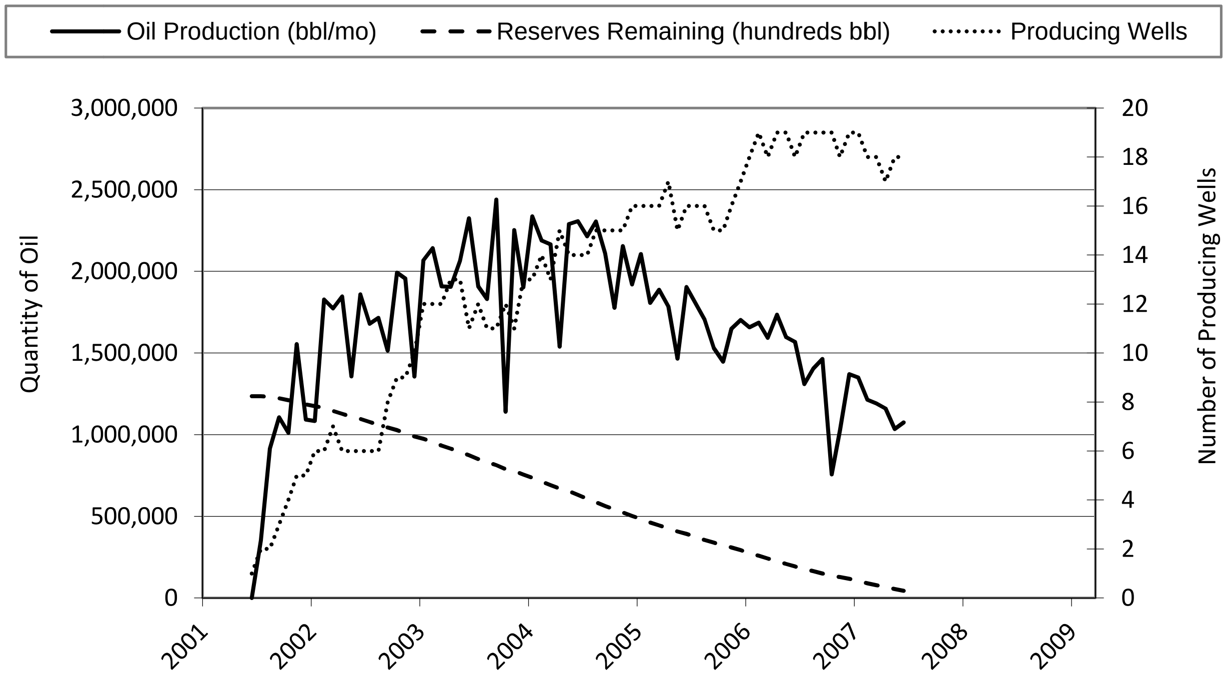

Figure 3: The historical number of producing wells, production rate, and reserves remaining for Northstar over time.

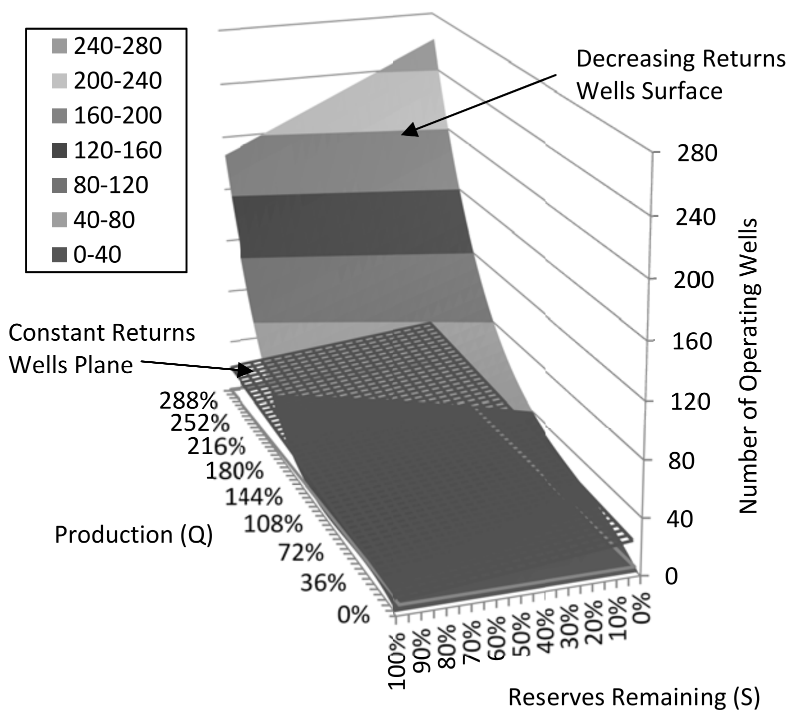

Figure 5: Northstar wells as a function of production (Q) and reserves remaining (S), with the constant returns plane and the decreasing returns surface shown. The horizontal and depth axes are given in percentage terms, from zero to 100% of original technically recoverable reserves and from 0% to 300% of historical maximum production rate.

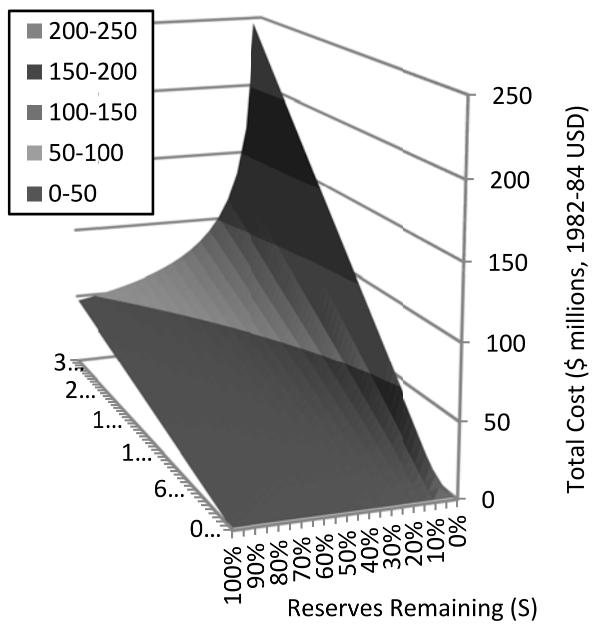

Figure 4: The base average total cost of production from Northstar for combinations of reserves remaining and production rate (given in percentage terms, from zero to 100 percent of original technically recoverable reserves in the field and from 0 to 300 percent of historical maximum production rate).

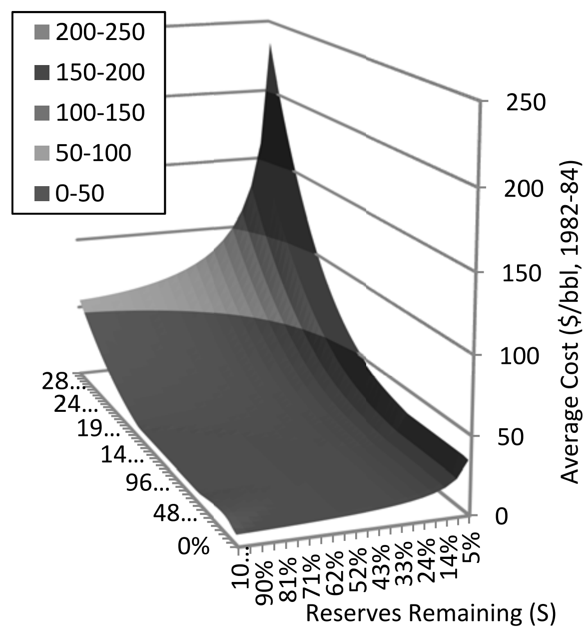

Figure 6: The composite cost function for Northstar in 2003.

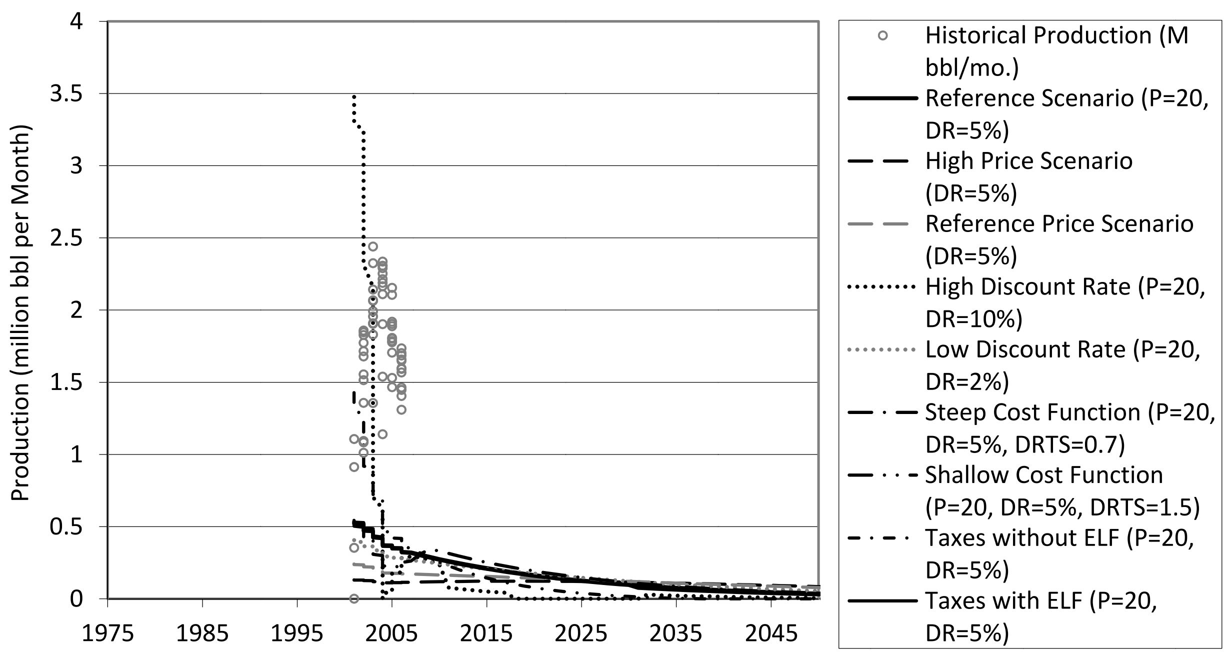

Figure 9: Sensitivity analysis for the un-calibrated model of Northstar (i.e., unconstrained for initial production rate and without adjustment costs).

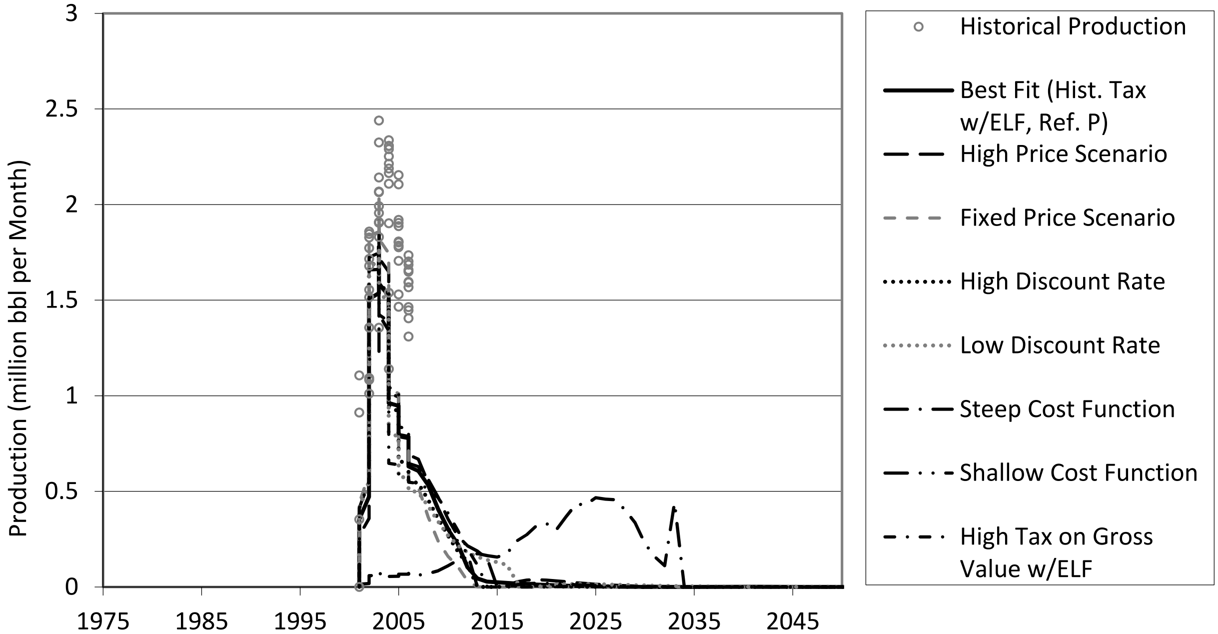

Figure 10: Sensitivity analysis of the calibrated model for Northstar.

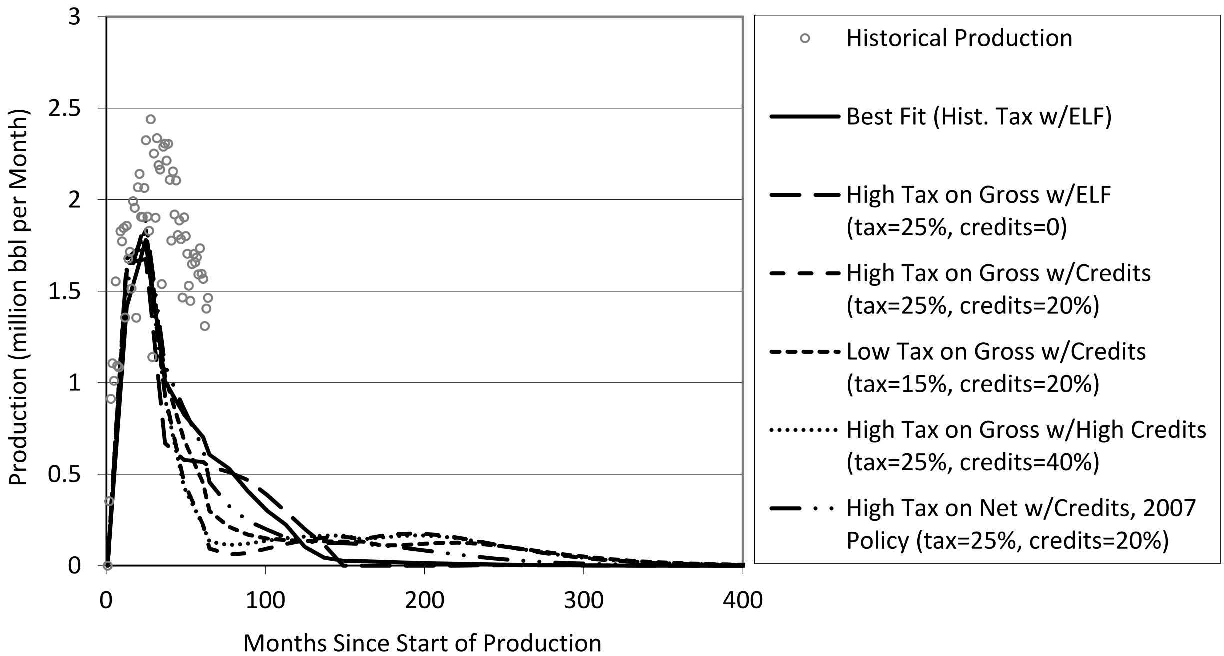

Figure 11: Historical Northstar oil production data, modeled economically optimal production with historical tax policy (Best Fit), and modeled economically optimal production under several tax policy scenarios.

Badami

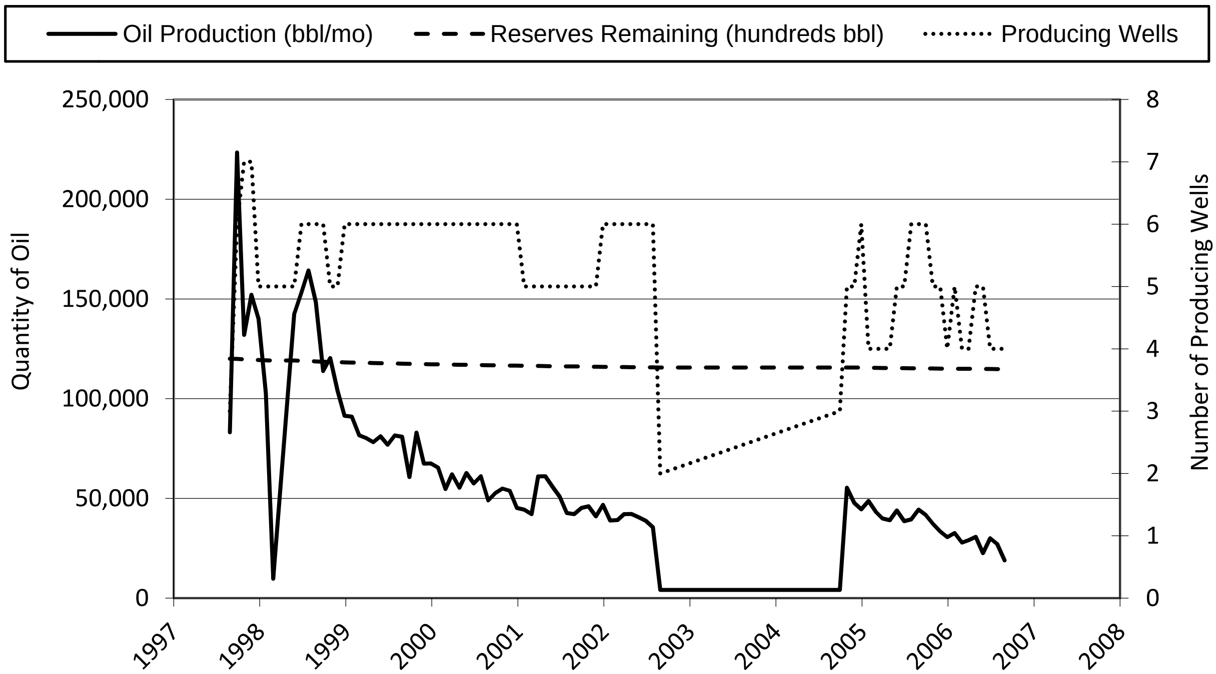

Figure 3: The historical number of producing wells, production rate, and reserves remaining for Badami over time.

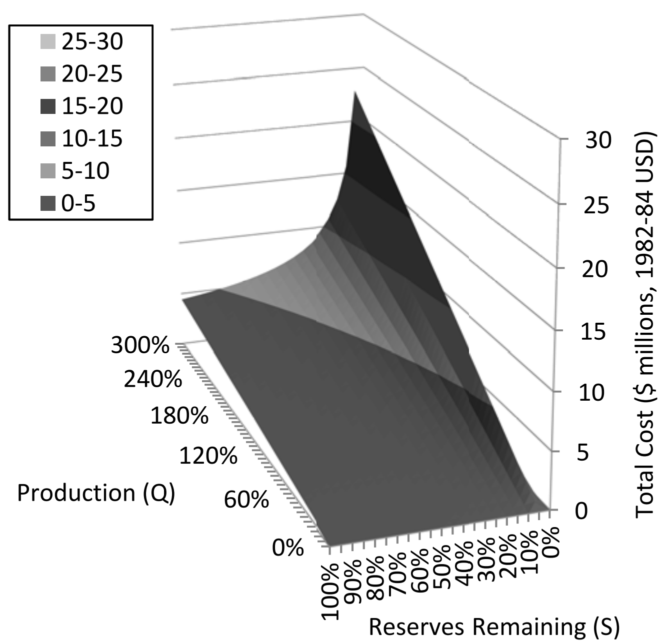

Figure 4: The base average total cost of production from Badami for combinations of reserves remaining and production rate (given in percentage terms, from zero to 100 percent of original technically recoverable reserves in the field and from 0 to 300 percent of historical maximum production rate).

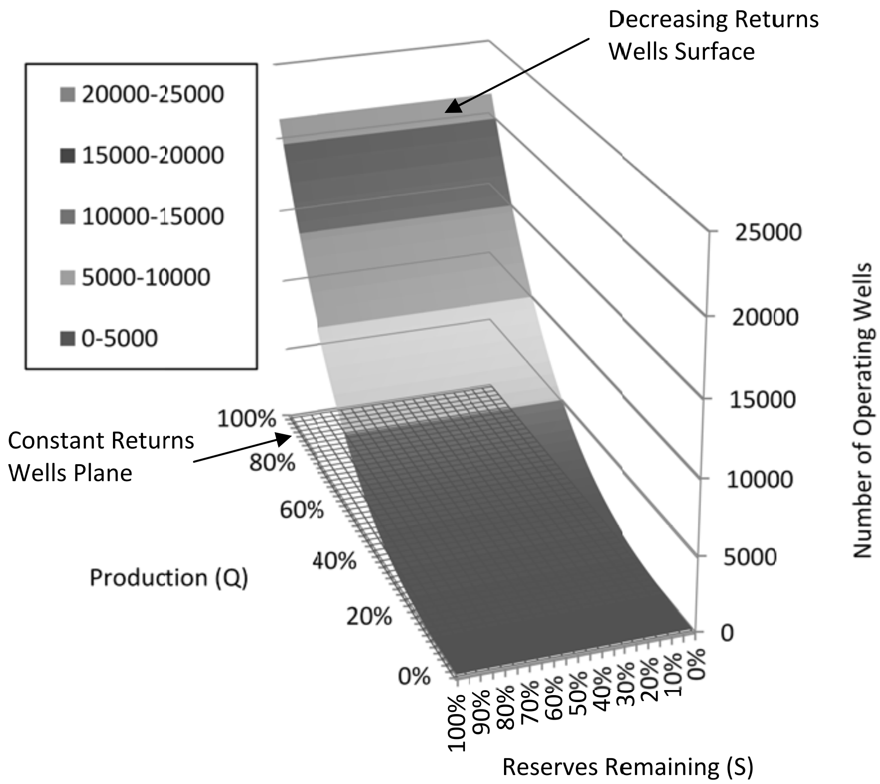

Figure 5: Badami wells as a function of production (Q) and reserves remaining (S), with the constant returns plane and the decreasing returns surface shown. The horizontal and depth axes are given in percentage terms, from zero to 100% of original technically recoverable reserves and from 0% to 100% of historical maximum production rate.

North Slope Aggregate Total

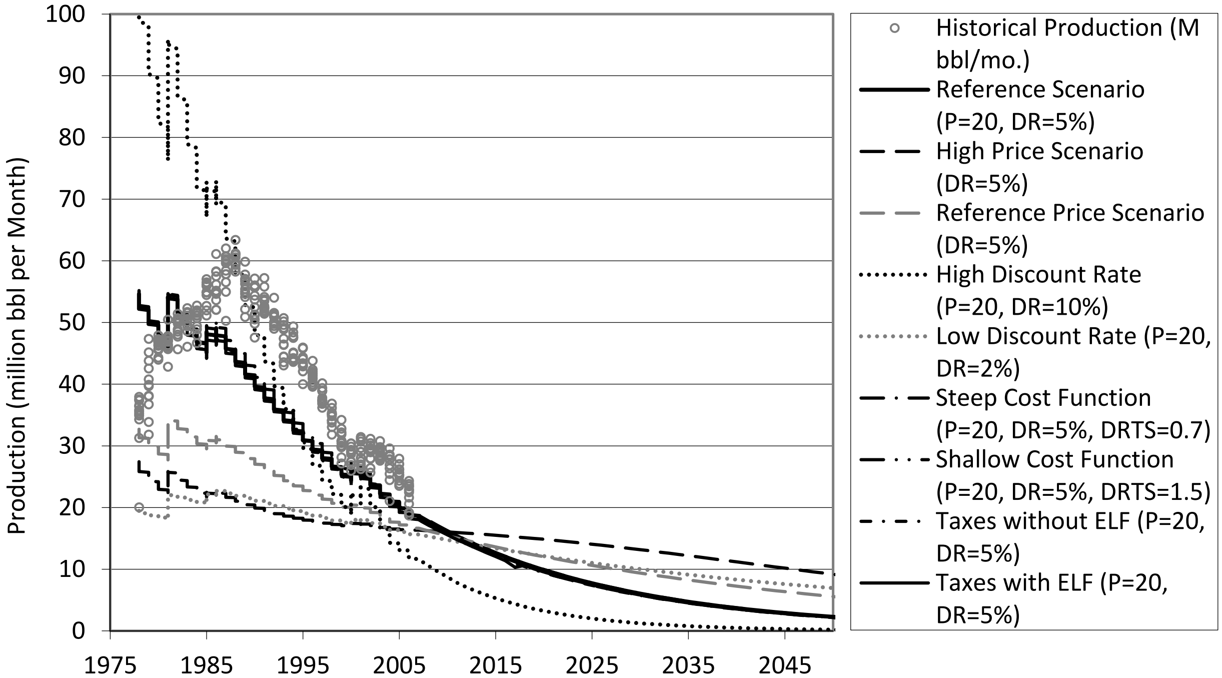

Figure 9: Sensitivity analysis for the un-calibrated model of the total North Slope (i.e., the sum of production from seven independently-optimized production units, unconstrained for initial production rate and without adjustment costs).

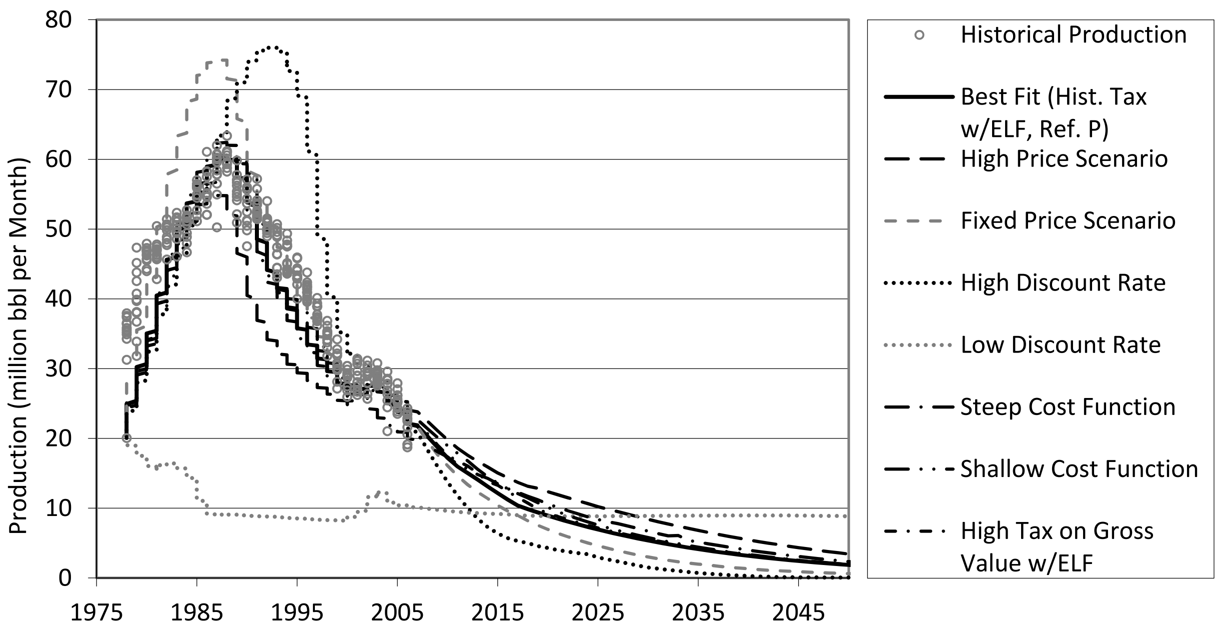

Figure 10: Sensitivity analysis of the calibrated model for the total North Slope (i.e., the sum of production from seven independently-optimized production units).

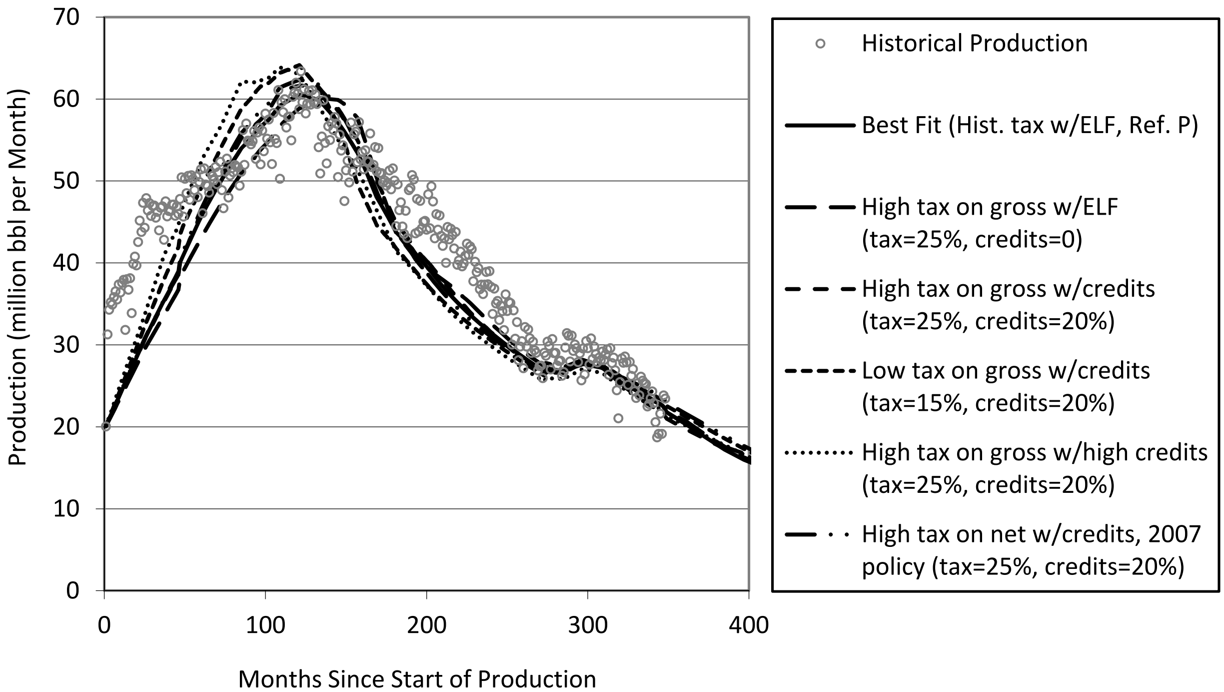

Figure 12: Historical total North Slope oil production data, modeled economically optimal production with historical tax policy (Best Fit), and modeled economically optimal production under several tax policy scenarios. The total North Slope production is the sum of production from seven independently-optimized production units.