An Integrated Analysis of the Potential for Carbon Storage, Utilization, and Risks of Fault Slip in the Cook Inlet Basin of Southcentral Alaska

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Abstract

Injecting carbon dioxide (CO2) into reservoirs has great environmental and oilfield development benefits, and also associated risks. This study shows the fluid storage potential of the Hemlock Formation in the whole Cook Inlet basin of southcentral Alaska. The Cook Inlet basin comprises of several oil and gas fields, producing hydrocarbons since the late 1950s. Oil reservoirs have undergone fluid injection for many years in order to enhance recovery. In this study, two 3D seismic surveys, several well-logs (~200 wells), and core data (~40 wells) were incorporated to analyze petrophysical and geomechanical properties and understand reservoir heterogeneities. There are several faults present in the basin, many of which affect the Hemlock Formation. Injection of fluid in the reservoirs can increase the pore pressure, which reduces the effective stress. This phenomenon increases the risk of fault slip. Results show that the Hemlock Formation is vertically and horizontally heterogeneous. The Hemlock reservoir consists of sandstone and conglomerates, with an average porosity of 15-20%. The formation has an estimated CO2 storage capacity of 0.91-16.13 Gigatonne (Gt), with a P50 value of ~4.33 Gt in the whole Cook Inlet basin. The reservoir quality of the Hemlock Formation is compared among the major oil and gas fields in the Cook Inlet basin. Structure, thickness, porosity, permeability, and net pay maps show the sweetspots for fluid injection in the basin at a regional scale. The variability among the individual oilfields for fluid storage capacities is due to the differences in regional change in

porosity, reservoir thickness, and the size of the field. Simple fault slip potential (FSP) models are developed in the Granite Point and Nicolai Creek fields (with 3D seismic surveys) in the basin using hydrologic and geomechanical parameters (e.g., poroelastic stiffness tensors and Biot's coefficient), and stress gradients from core, well-log, and formation test data, and standard fluid injection information. These models estimate the cumulative conditional probability of slip of the known faults at a certain injection rate over time, not the exact slip amount. The FSP models show that the azimuth of the maximum horizontal stress (SH_{max}), fault dip, pore pressure, and vertical stress (Sv) gradient are the most sensitive parameters.

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