The Role of Static and Dynamic Modeling in the Fort Nelson CCS Project

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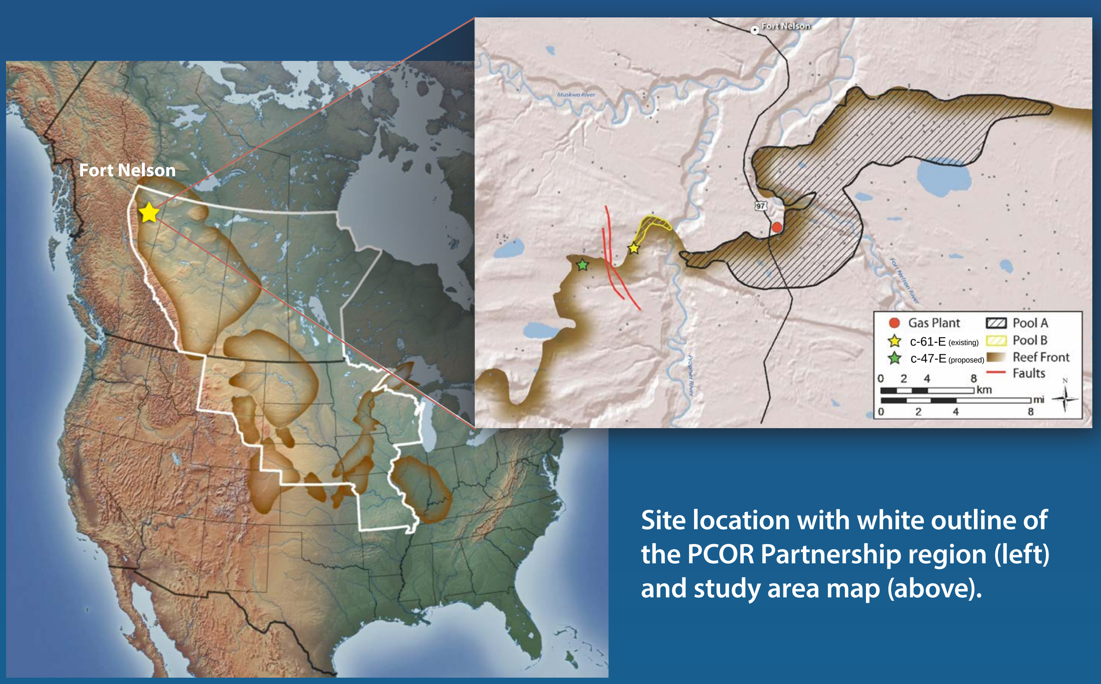
Abstract

Spectra Energy Transmission and the Energy & Environmental Research Center, through the Plains CO_2 Reduction (PCOR) Partnership, are investigating potential commercial-scale carbon capture and storage (CCS) in a saline formation near Fort Nelson, British Columbia, Canada, by conducting detailed modeling and predictive simulations of injection at the Fort Nelson site. The results of the Fort Nelson modeling activities are providing insight regarding the movement of sour CO_2; the potential effects that large-scale sour CO_2 injection may have on neighboring natural gas production fields; and the deployment of selected monitoring, verification, and accounting (MVA) techniques.

Study Area

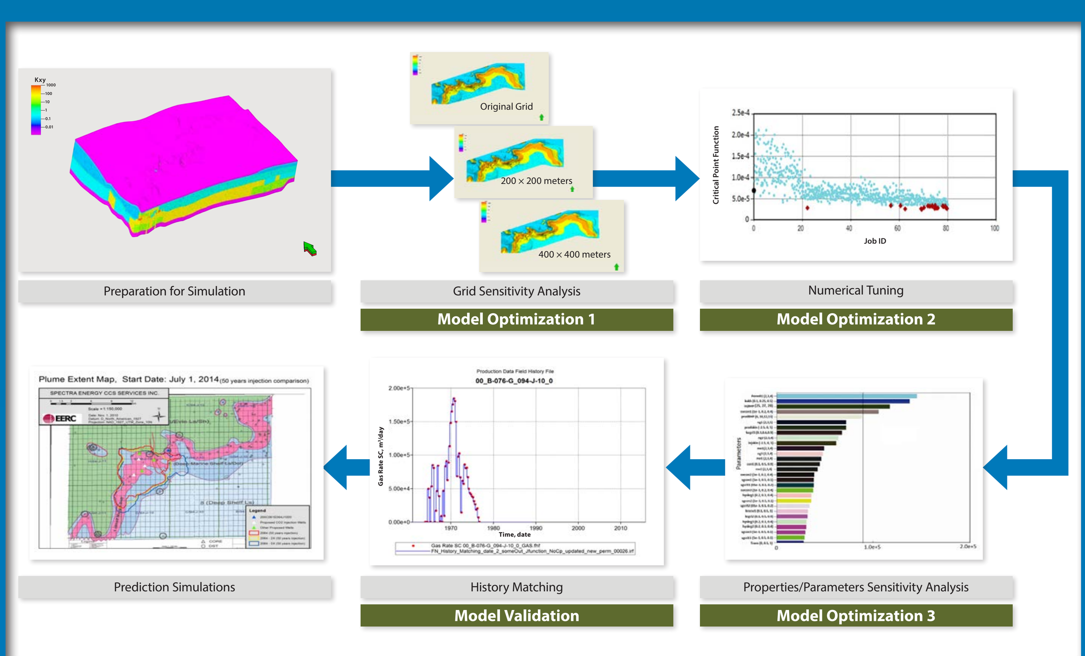


Site location with white outline of the PCOR Partnership region (left) and study area map (above).

Methodology

The method used in this study is an integrated, iterative, risk-based approach for defining MVA strategies. Site characterization, modeling and simulation, risk assessment, and the development of a cost-effective MVA plan are the four key components iterated during the course of a CCS project. This approach will be applied through the feasibility, design, injection, closure, and postclosure periods of the project. Each iteration will improve the technical and cost-effectiveness of the MVA plan, while simultaneously reducing project risks.

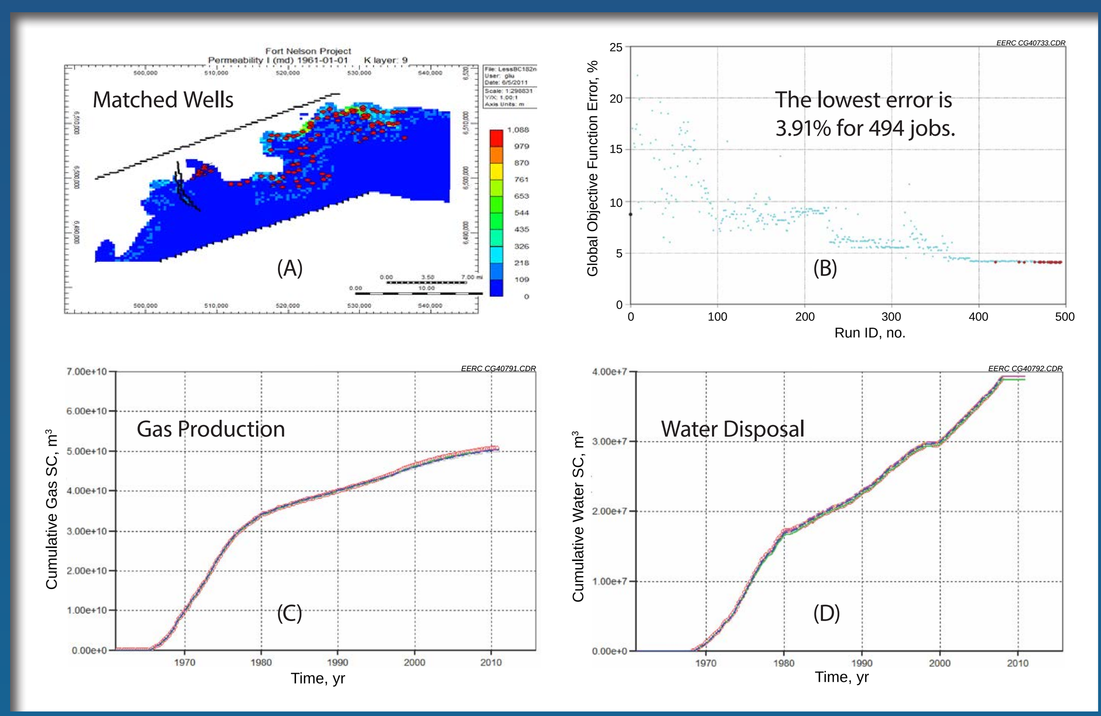
In order to more effectively integrate the modeling and simulation into the overall MVA strategy, a dynamic modeling workflow was developed [1]. The workflow utilizes three techniques: 1) grid-size sensitivity analysis, used to create the coarsest grid resolution that will yield accurate results; 2) numerical tuning to speed up simulation run time and minimize material balance error; and 3) property/parameter sensitivity analysis to identify the properties and parameters that have the greatest effect on the simulation results. The optimized model is then validated by history matching to obtain a reasonable match between simulated results and historical data before predictive CO_2 simulations are run [1].



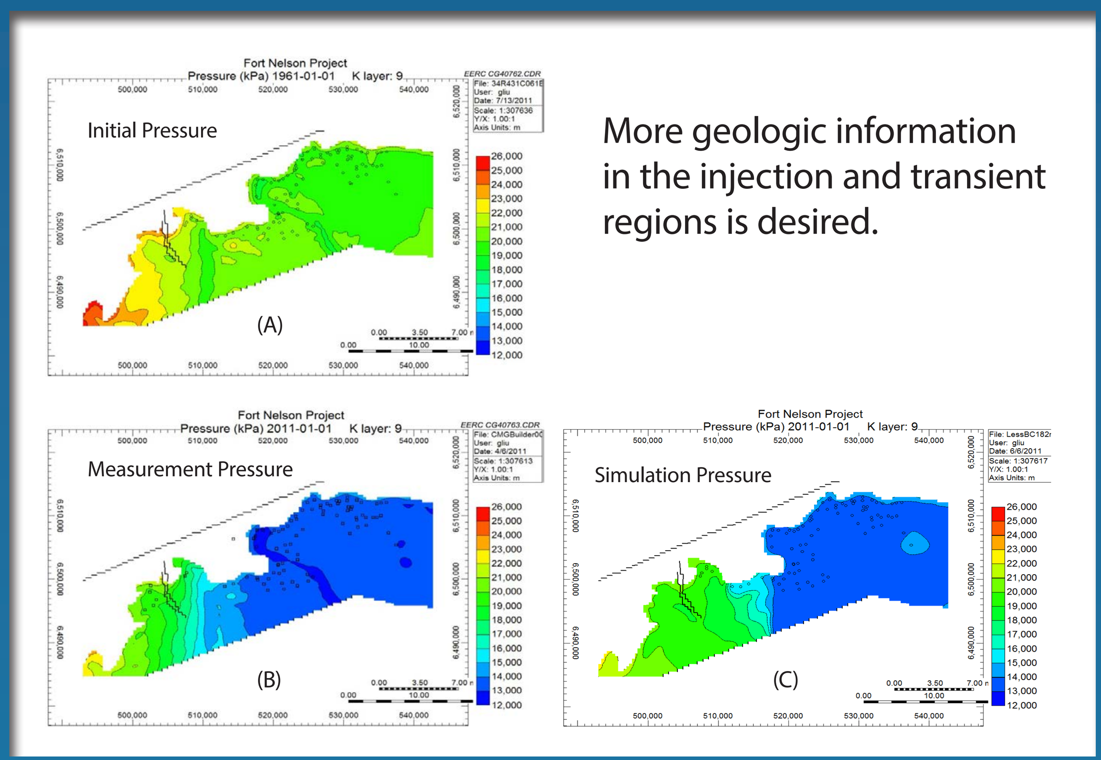
Dynamic modeling workflow.

Results of History Matching

A history-matching process was used to improve modeled outputs and to obtain a good match with historical data, which demonstrates the ability of the model to accurately predict reservoir conditions. A total of 92 wells were utilized, including 85 production wells and seven water disposal wells in the study area, primarily in the nearby gas fields. The goal of this step was to match gas and water production, water disposal, and well bottomhole pressure (BHP). Ultimately, by matching these parameters in the nearby gas pools, a more accurate geologic model with a current matched distributed regional pressure profile could be used. After 494 history-matching simulation runs, an asymptotic convergence was achieved with a total of 92 wells matched. Upon convergence, the global objective function error between the simulation runs and the historical data was 3.91%. Correspondingly, a comparison of the historical and simulation data for cumulative gas production and cumulative water disposal is shown in the figures below. These history-matching results indicate a good match for gas and water production, water disposal, and BHPs for all wells in the investigated area.



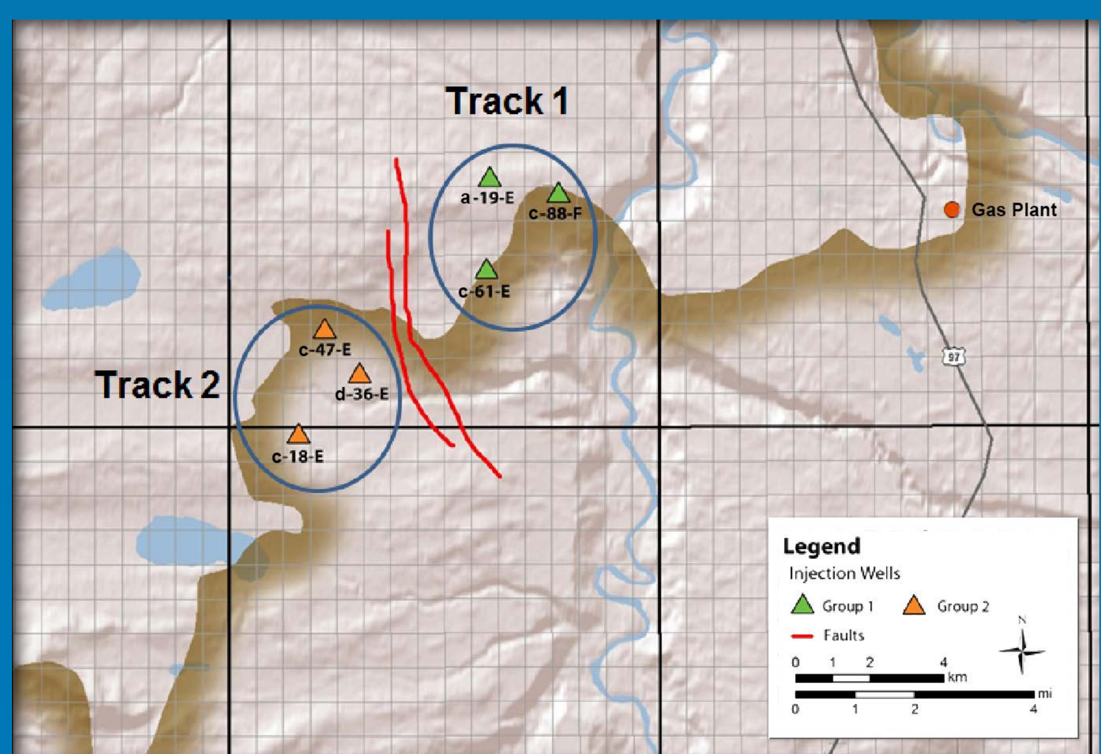
History-matching results: A) location of matched 92 wells, B) global objective function error after 494 simulation jobs, C) cumulative gas production, and D) cumulative water disposal based on the top five "best"-matching cases (SC indicates standard conditions: 15.5°C, 101.25 kPa).



Pressure distributions: A) initial pressure distributions, B) measured pressure distributions (January 2011), and C) matched pressure distributions.

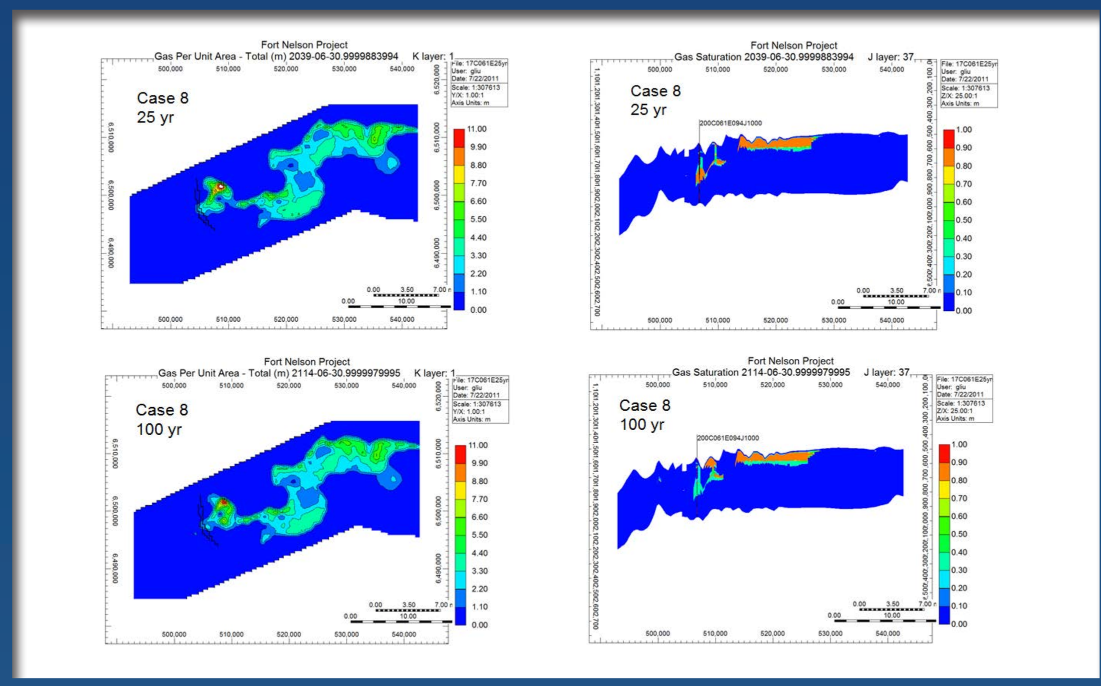
Results of Two Injection Scenarios

Initial simulations were run on three wells, including c-61-E (Track 1) at a rate of 120 MMscf/day for 25 years. An additional 75-year postinjection period was also modeled to address CO_2 movement and reservoir pressure buildup. These simulations indicated that 120 MMscf/day could be injected for 25 years, although CO_2 and elevated pressure may contact both nearby gas pools within the 100-year simulation period. This simulation output was also utilized in a subsurface technical risk assessment, which indicated that CO_2 contacting the gas pools may present an unacceptable risk. As a result, an alternative injection location was selected farther to the west (Track 2). In addition, new geologic data were collected, and the geologic model was updated with additional well and seismic information. The injection simulations were then rerun on both Track 1 and Track 2. While both injection scenarios indicate the formation can accept 120 MMscf/day for 25 years, the simulation for Track 2 indicates CO_2 does not contact either gas pool in the 100-year simulation run. Additional characterization should be performed around both injection tracks to better understand the potential storage reservoir at Fort Nelson.



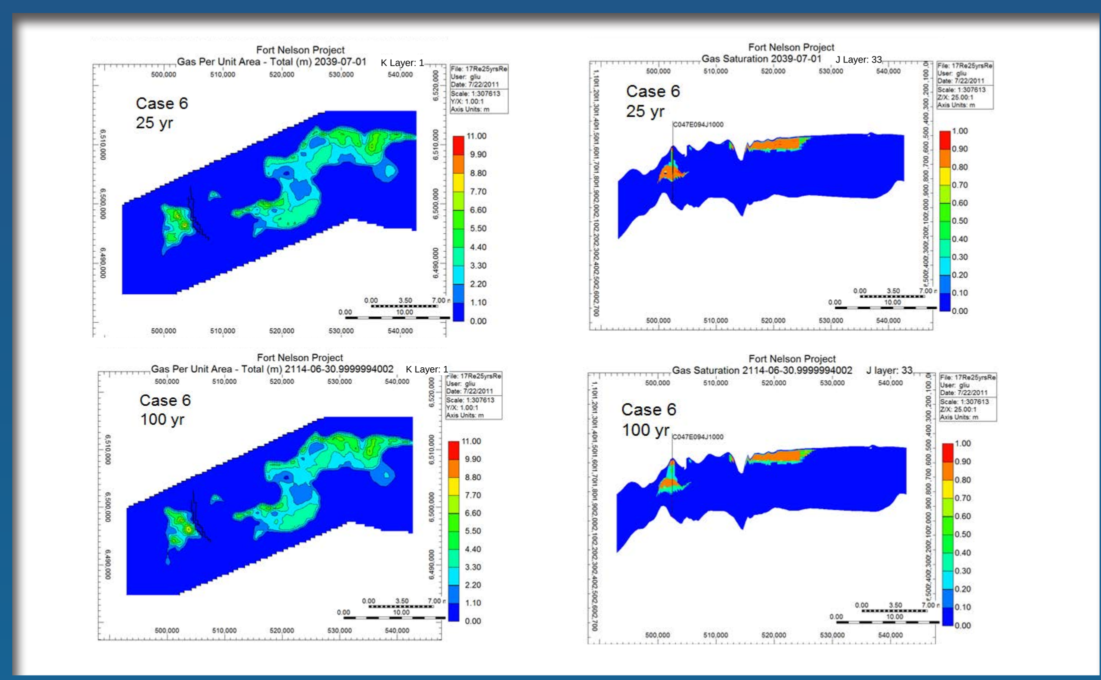
Location potential of injection wells.

Track 1

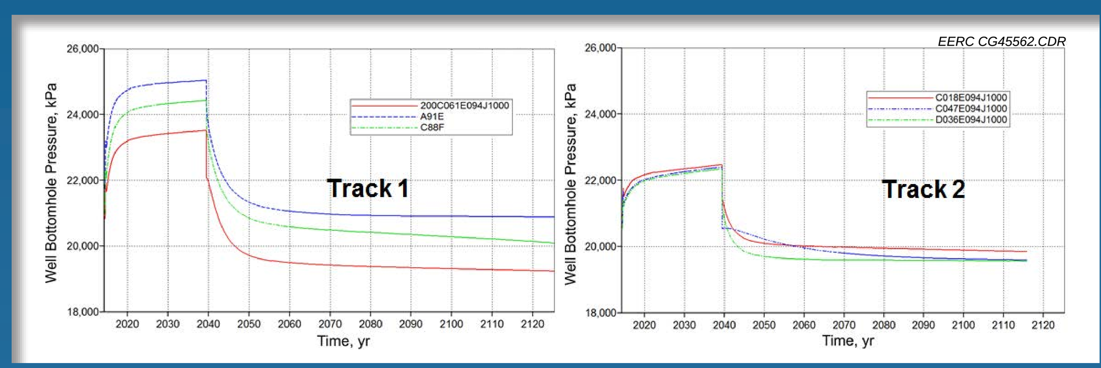


Track 1: CO_2 plume migration over time – plane view (left) and cross-sectional view (right).

Track 2



Track 2: CO_2 plume migration over time – plane view (left) and cross-sectional view (right).



BHP plots by each injection well, in tracks.

Conclusion and Future Work

The static and dynamic modeling in the Fort Nelson CCS Project plays a crucial role in predicting the movement of sour CO_2 in the reservoir, informing the risk assessment, and helping to define and develop the MVA plan. The proposed dynamic modeling workflow, along with the integrated approach to site characterization, modeling and simulation, and risk assessment, can lead to a more targeted, site-specific, and technically and economically feasible MVA plan and CCS project.

Both injection locations (Track 1 and Track 2) appear to have sufficient capacity to accommodate the target injection volumes. However, current knowledge suggests that Track 2 may be a better option (compared to Track 1) because the injected sour CO_2 has a more contained CO_2 footprint and does not contact the adjacent gas pools during the 100-year simulation period. In addition, the injection well BHPs in Track 2 were predicted to be 1000 to 3000 kPa lower than the injection well BHPs in Track 1. Overall, Track 2 has a lower risk profile; however, the collection of 3-D seismic data and the drilling of an additional well in the vicinity of Track 2 are necessary to determine whether or not the geology is suitable for the injection of 3.4 MMm³/day (120 MMscf/day) for 25 years.

Future work includes the development of an MVA plan for both Track 1 and Track 2 based on the results of site characterization, modeling and simulation, and risk assessments. This MVA plan will be updated along with the modeling and simulation and risk assessment once additional site characterization activities are completed.

Reference

[1] Gorecki CD, Sorensen JA, Klapperich, RJ, Botnen, LS, Steadman EN, Harju JA. A risk-based monitoring plan for the Fort Nelson feasibility project. Presented at the Carbon Management Technology Conference, Orlando, FL, February 7–9, 2012. SPE Paper CMTC-151349-MS.

Acknowledgments

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PCOR Partnership 2003 – Present