Minus CO2 Challenge 2021/2022 – Student teams evaluate potential world-class carbon storage capacity offshore Nova Scotia, Eastern Canada

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Introduction

In the third edition of the Minus CO2 Challenge, the EAGE invited multidisciplinary teams of university students to present their assessment of carbon storage potential in deep saline aquifers and depleted hydrocarbon fields offshore Nova Scotia, Eastern Canada. Based on this, they have developed strategies for carbon neutrality in the region by 2050. In total, nine teams received a dataset assembled by Dalhousie University to develop their ideas. For competition purposes, well log data were made available by Divestco, and regional NovaSPAN seismic data by ION. Key references and websites were provided and are listed here, with some additions.

The best four teams were selected to present their work to the jury by video conference and after a close-run discussion placed: (1) Indian Institute of Technology (IIT; Bombay, India), (2) Federal University of Bahia (UFBA; Bahia, Brazil), (3) Khalifa University of Science and Technology (KUST; Abu Dhabi, United Arab Emirates), and (4) University of Stavanger (UiS; Stavanger, Norway). Congratulations to the finalists, and all the teams that participated.

This article presents a summary of the results, highlighting the leading contributions of each of the finalists, with comparison to storage estimates by the organizers, and comparison to analogue offshore basins in the USA, Norway, and UK (via online carbon storage atlases). It is, to our knowledge, the first comprehensive quantitative assessment of storage capacity on the margin to be published. And, although by nature a competition, we emphasize the value of multiple independent ideas followed by, in effect, peer review and collaboration.

Carbon storage potential offshore Atlantic Canada (Figure 1) was recognized by Bachu (2003) and in the 2005 IPCC Special Report on Carbon Storage based on work by Bradshaw and Dance (2005). In 2010, Pothier, Wach and Zentilli systematically assessed reservoir-seal pairs in the region, identifying significant injectivity, storage and containment potential on the Scotian Shelf, but expressed reservations about porosity and permeability in Paleozoic basins onshore, consistent with an exploratory well drilled by an industry, government, university consortium in 2014 (the CCS1 well in Cape Breton: OERA, 2017).

Deep-water exploration on the Scotian Slope has yet to reveal extensive reservoir/aquifer development (OERA, 2011 & 2019) but extensive salt diapirism presents an additional opportunity, recognized by the UiS team, at the experimental frontier of carbon storage (e.g.: da Costa et al., 2020). This observation also leads to consideration of a few diapirs on the shelf. Caverns in older salt formations onshore Nova Scotia have been used for methane storage and considered for compressed air storage in an area with existing (and high potential) wind, tide, and pipeline infrastructure (Dusseault, Bachu and Rothenberg, 2004; Dusseault and Wach, 2020). A $75 million methane storage project at Alton demonstrated the principle but has recently been discontinued for commercial reasons (Henderson, October 2021).

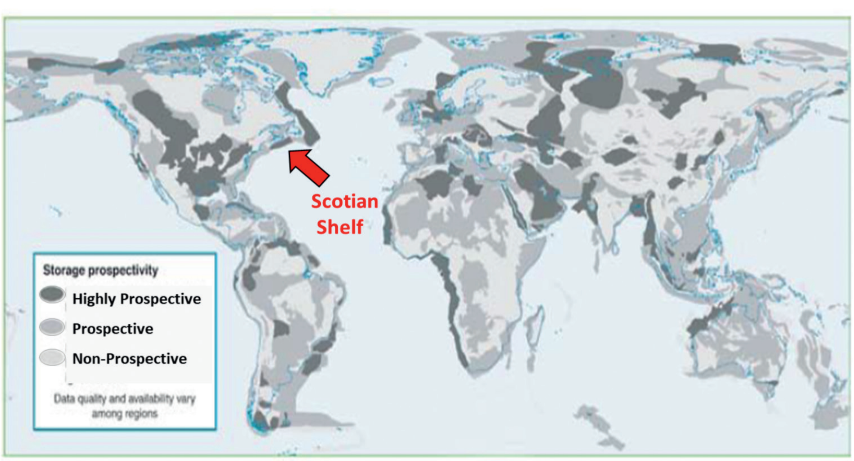

Figure 1 Global prospectivity geological storage of CO_2 (IPCC,2005; Bradshaw and Dance, 2005).

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Carbon storage potential – deep saline aquifers on the Scotian shelf

The teams were first asked to estimate storage potential in deep saline aquifers on the shelf, within an extensive (~700 km by ~150 km) monoclinal wedge of Middle Jurassic to Late Cretaceous sediments that subcrop seabed glacial deposits approaching the coast of Nova Scotia Figures 2, 3 and 4). These post-rift sediments were deposited as successive mixed siliciclastic-carbonate systems on a classic low-latitude passive margin. High porosity-permeability aquifers are focused at the seaward margin of the Bajocian-Barremian Abenaki-Roseway Carbonate Bank (Abenaki and Missisauga Formations), in intercalated paralic silici-clastics sourced from Nova Scotia (Mohawk, MicMac and Lower Missisauga Formations), and in the Kimmeridgian-Cenomanian Sable Island Delta (MicMac, Missisauga and Logan Canyon Formations) that progressively interfingered with and overwhelmed preceding systems, sourced from the Avalon uplift to the north, in Labrador and Newfoundland. These forestepping systems each exceed 1500 m thickness at their respective shelf-edges (Figures 5 and 6) where they transition to hemipelagic muds, marls, and silts on the slope. They are capped by low permeability Late Cretaceous and Cenozoic mudstones (e.g.: the Dawson Canyon Formation) and marls/chalks (e.g.: the Wyandot Formation) which provide a regional topseal. There are many intra-formational seals, some of which are regionally extensive, notably the 'O' Marker (a succession of low perme-ability, diachronous, shelfal oolitic limestones at the top of the Middle Missisauga Formation) and the Naskapi Shale (the lowest member of the Logan Canyon Formation) which provides topseal in six fields.

Teams estimated reservoir/aquifer properties from digital logs in 40 wells calibrated by core data (representative of 207 wells on the margin) and then derived gross rock volumes and net pore volumes in three zones using four regional structural

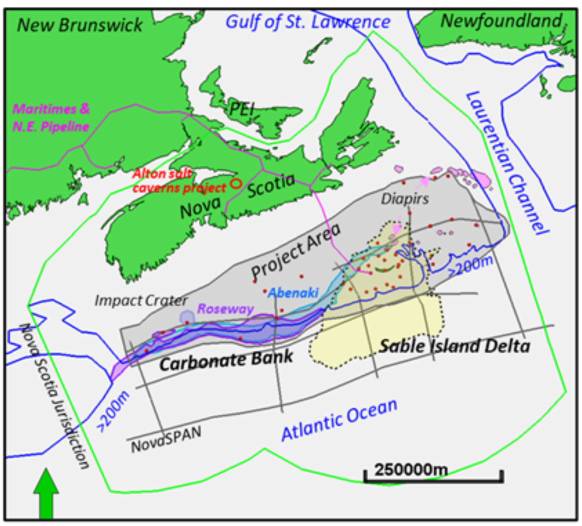

Figure 2 Nova Scotia Margin showing the project area on the Scotian Shelf, the 200m isobath (shelf-to-slope), the Abenaki Carbonate Bank (Kidston et al., 2007) and the Sable Island Delta (Kendell and Deptuck, 2012).

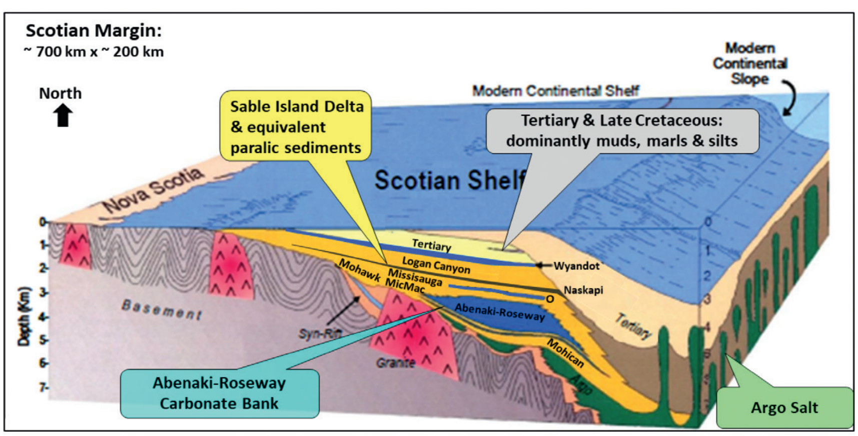

Figure 3 Perspective view of the Scotian Margin showing the Abenaki-Roseway Carbonate Bank, the Sable Island Delta, and key post-rift litho-stratigraphic formations. Based on OERA, 2011 (after J. Wade, modified Grant,1986, CNSOPB,2009).

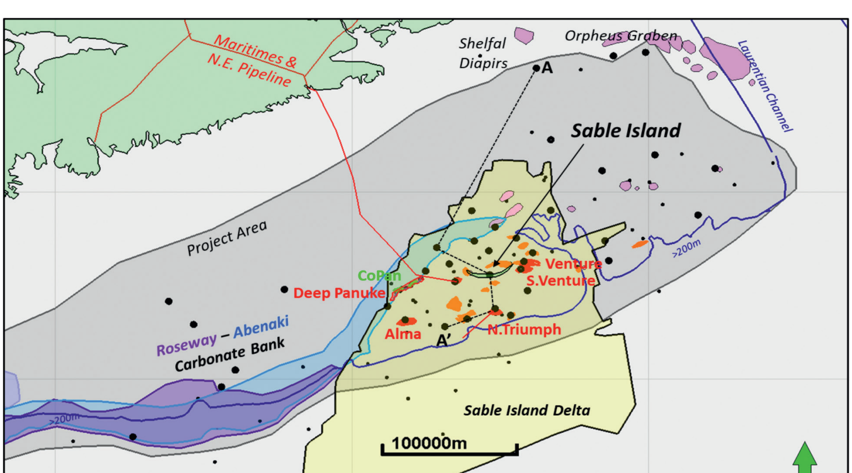

Figure 4 Depleted gas and oil fields (red: Deep Panuke and Sable Gas Project; Green: CoPan). stranded gas fields (orange). Project wells = large dots; other wells = small dots. A-A' = location of cross-section in Figure 5.

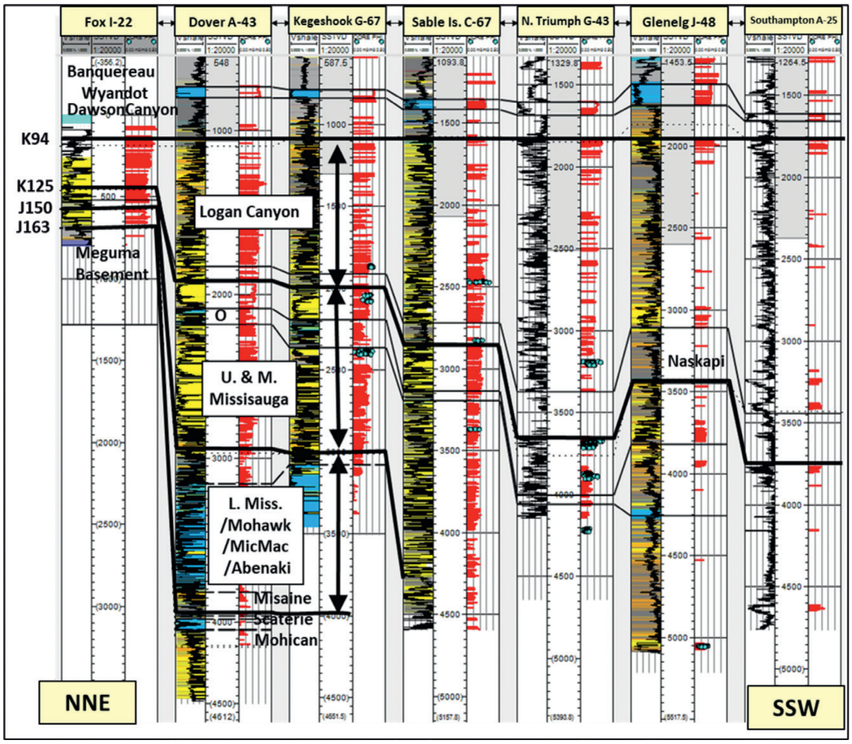

Figure 5 Well log cross section A-A′ datumed on K94. Location Figure 4. Left track: Vshale (0-1) with lithology from cuttings (Fensome, OERA, 2011, where available). Yellow=sand, orange silt, grey/brown=mudstone, blue marl - chalk, limestone, marl Centre track: True vertical depth subsea. Right track: Red=sonic porosity (0-50%): Hunt Gardner Rayner with Vshale cutoff and 10% porosity cutoff (+30% cutoff in model). Blue dots= core porosities 0-50% (OERA, 2011). Horizons are based on K94, K130, J150 and J163 surfaces from OETR (2011), and are used to define 3 zones: Logan Canyon, U. & M. Missisauga, L. Missisauga / Mohawk / MicMac / Abenaki.

horizons provided by the organizers (as ASCII files and in a Petrel framework – courtesy Schlumberger). The structural model was built by the organizers from online digital data in the Nova Scotia Play Fairway Analysis (K94, K130, J150 and J163 horizons; OERA, 2011) and extended landward to the regional onlaps and subcrops using the Geological Survey of Canada atlas of the margin (Cant,1991). Three zones were layered for properties: Logan Canyon (K94-K125), Upper and Middle Missisauga (K125-J150) and the Abenaki with its coeval Mohawk, MicMac and Lower Missisauga clastics (J150-J163). Storage capacity in deep saline aquifers was then estimated using storage efficiencies in the 1-8% range (based on analogues and numerical models, notably in online Norwegian and American carbon storage atlases: NPD, 2019; US DOE 2010 & 15; Vidas et al., 2014). The density of supercritical CO_2 used in calculations was typically ~0.7 gm/cc.

Scotian Shelf - Deep Saline Aquifers (Effective Storage)	Gt CO2	Gt CO2	Gt CO2
Organizers: Min. - Base Case - Max.	7	151	1280
KUST: P90 - P50 - P10	99	658	1472
IIT: Mean and Max.	-	215	648
Analogues - Deep Saline Aquifers (Effective Storage)	**Gt CO2**	**Gt CO2**	**Gt CO2**
USA Gulf of Mexico: Low Avg. High (Vidas, 2012)	429	3198	5967
USA Offshore Carolinas: Low Avg. High (Vidas, 2012)	47	317	587
UK North Sea and Irish Sea: P50 (Bentham, 2014)	-	67	-
Norway North Sea: Summary (NPD, 2019)	-	46	-

Scotian Shelf - Depleted and Stranded Fields (Effective Storage)	Gt CO2	Gt CO2	Gt CO2
Organizers: Storage Efficiency = 50%, 75%, 100%	0,147	0,221	0,295
KUST:	-	0,336	-
IIT:	-	0,319	-
UFBA:	-	0,248	-
Analogues - Depleted Fields (Effective Storage)	**Gt CO2**	**Gt CO2**	**Gt CO2**
USA Gulf of Mexico: Low Avg. High (Vidas, 2012)	-	15	-
UK North Sea and Irish Sea: P50 (Bentham, 2014)	-	8	-
Norway North Sea: Summary (NPD, 2019)	-	13	-

Table 1 Estimates of effective CO2 storage capacity on the Scotian Shelf with comparison to analogue basins.

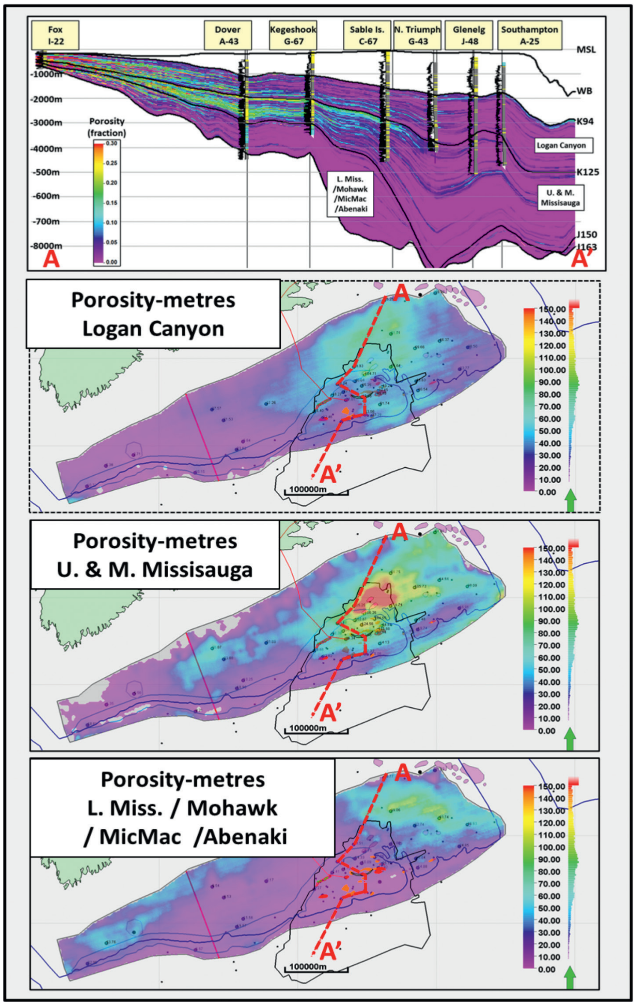

Figure 6 3 Zone porosity model of the Scotian Shelf. Vshale and lithology logs are shown on the transect. Porosity-meters of aquifer are show for the Logan Canyon zone, upper and middle Missisauga zone and the Lower Missisauga, Mohawk, MicMac, Abenaki zone. The influx and waning of the Sable Island Delta from the NNE is apparent.

Using a Monte Carlo simulation the KUST team estimated P90, P50, and P10 storage capacities at 99, 658 and 1472 $GtCO_2$. Similarly, the IIT team estimated a mean of 215 and a maximum of 648 $GtCO_2$ via a probabilistic model. These storage estimates for the shelf as a whole (Table 1) compare reasonably to a base case of 151 $GtCO_2$ by the organizers that was derived by propagating sonic porosities (with cutoffs) throughout the Petrel framework and applying a base case storage efficiency of 3% and a depth interval of -800 to -4000m. A transect through the porosity model and porosity-thickness maps are shown in Figure 6. Bracketing sensitivities ranging from 7 to 1280 $GtCO_2$ were derived using storage efficiencies of 1-8%, depth intervals that ranged from 800-3000 m subsea to 800-5000 m subsea and by varying average net-to-gross and porosity. Based on an analysis by Kearns et.al (2017) a wide range of scoping estimates between workers is not unusual: USGS and US DOE estimates of storage capacity in the USA are consistent at the low end, but medium estimates vary by a factor of 2 and at the high end by a factor of nearly 4.

The UFBA team used an innovative machine learning approach to assess a specific aquifer within a sub-area. Seismic clustering was used for seismic horizon picking. Statistical treatment of core data high-graded the Upper Missisauga Formation (below the Naskapi Shale). A random forest model led to well log permeability prediction. Joint seismic data and isopach map analysis led to calculating an injectable mass of 42 MtCO2 in the sub-volume considered.

UiS assessed four sub-regions, two on the shelf and two on the slope with theoretical storage capacity (the physical limit the geological system can accept: IEAGHG, 2009) between 890 and 1498 Gt CO_2 (equivalent to effective capacity of 45-75 Gt CO_2 with a 5% efficiency factor).

Carbon storage potential – comparison to deep saline aquifers in analogue basins

Compared to offshore basins in the US (Vidas et al., 2012), Scotian Shelf estimates are similar to the Atlantic margin off the Carolinas (Low, Average, High: 47,317,587 $GtCO_2$) but, unsurprisingly, smaller than the Gulf of Mexico (429, 3198, 5967 $GtCO_2$). The Atlantic margin off New Jersey is not assessed but probably has similar potential to offshore Nova Scotia.

Compared to storage estimates in similar areas of the North Sea (45 $GtCO_2$, *Norwegian Petroleum Directorate Atlas*; 70 $GtCO_2$, CO_2STOR in the UK, Bentham et al, 2014) Scotian Shelf estimates are somewhat higher, probably because of the large sediment supply with less structural-stratigraphic complexity (apart from a few shallow salt diapirs – which present a risk of leakage (O'Connor et al., 2019) – and local, deep, overpressured depocentres controlled by shelf-margin listric growth-faulting). Aquifer quality improves updip in these sand-rich fluvio-deltaic-estuarine systems and without large traps this results in a comparatively small hydrocarbon endowment with relatively small storage potential in depleted and stranded fields (Table 2: base case storage estimates).

On the other hand, a massive, unconfined, system of hydro-pressured aquifers (extensively interbedded with low permeability mud and marlstones) likely enhances dispersal of injected CO_2 (and residual trapping), reduces the risk of pressure build up and geomechanical failure (IIT team), and is favourable for injectivity at wells (IIT team). Detailed modelling, incorporating sand-filled distributary and estuarine channel systems is needed to refine migration pathways modelled by O'Connor et al. in 2019 (which used coarse sub-regional grids and a default relative permeability curve).

Carbon storage potential – depleted and stranded fields

Five gas fields within the Sable Island Delta (rollover anticlines above shelf-margin, down-to-basin, listric faults) were developed and produced between 1998 and 2018 in the Sable Gas Project (cumulative production 2.1 TCF) and were decommissioned leaving an abandoned offshore pipeline that was connected to the onshore Maritimes and Northeast pipeline (Figure 2). Also, within the delta, two small oilfields (CoPan Project) produced 44.5 MBO between 1992 and 1999 from low-relief drapes above the downdip raised-rim of the Abenaki Carbonate Bank. The bank itself produced 147 BCF of gas between 2013 and 2018 (Deep Panuke Project) from a structural-stratigraphic-diagenetic trap within its hydrothermally altered downdip seaward margin. About 2 TCF of gas resources remain undeveloped, mainly in rollover anticlines similar to the Sable fields. The location of these fields is shown in Figure 4 and base case storage capacity in each field is summarized in Table 2.

Teams assessed carbon storage potential in the depleted and stranded fields (as if they had been produced) by material balance from cumulative production and P50 resources published online by the Canada Nova Scotia Offshore Petroleum Board (Smith et al., 2014). PVT data and formation volume factors are available online in field development plans lodged by the operators, and the above report. Carbon storage based on reservoir pore volumes calculated from produced (or producible) hydrocarbons was typically estimated with a storage efficiency of 75% based on the IEA GHG 2009 Technical Study 'CO2 Storage in Depleted Gas Fields'.

The results were quite consistent (Table 1). Totaling all fields, the organizers estimated low, medium, and high cases of 147, 221 and 295 $MtCO_2$ (evenly split between depleted and stranded fields); KUST estimated 336 $MtCO_2$, IIT 319 $MtCO_2$, UFBA 248 $MtCO_2$. This compares to much larger published estimates in North Sea fields (13 $GtCO_2$ Norway; 8 $GtCO_2$ UK) and a surprisingly low estimate in the Gulf of Mexico (15 $GtCO_2$).

South Venture field simulation

The teams were provided with a static model of South Venture Field and, if simulation software were available (courtesy Schlumberger), were asked to history match production (~ 315 BCF) followed by injection of CO2 to identify when injected CO2 would spill outside structural closure (providing an estimate of storage efficiency within the trap – if that is a concern, bearing in mind that residual trapping in deep saline aquifers is widely considered adequate without a conventional hydrocarbon trap).The UiS team achieved good history matches to production, as did the University of Manchester and Heriot Watt University who were not among the finalists. Assessing leakage outside spill was more difficult, requiring assessment of cross-fault reservoir juxtapositions at the north bounding

Depleted fields	CNSOPB published cumulative production		Estimated weighted FVF (Estimated from Dev. Plans)	CO2 Storage Density=0.7 E= 75%
	BCF / MBO	103 sm3	sm³/rm³	Mt CO2
S.Venture	314.6	8,908,194	285.0	16.4
Venture	493.6	13,977,451	350.0	21.0
North Triumph	292.2	8,273,692	300.0	14.5
Alma	516.0	14,612,931	250.0	30.7
Thebaud	501.3	14,194,298	360.0	20.7
Sub-Total	2117.7	59,966,566		103.2
Deep Panuke	147.3	4,170,559	400.0	5.5
CoPan	44.5	7,066,810	0.8	4.6
Total	2264.9	131,170,500		113.4
Stranded Gas Fields (if depleted)	**CNSOPB SDL Report (2014) P50 Resources**		**Estimated weighted FVF (Estimated from report)**	**CO2 Storage Density=0.7 E= 75%**
	BCF	10^9 M3	sm³/rm³	Mt CO2
Arcadia	158	4.5	400	5.9
Banquereau	170	4.8	280	9.0
Chebucto	66	1.9	275	3.6
Citnalta	172	4.9	290	8.8
Glenelg	508	14.4	270	28.0
Intrepid	54	1.5	260	3.1
Olympia	143	4.1	350	6.1
Onondaga	304	8.6	250	18.1
Primrose	127	3.6	160	11.8
South Sable	8	0.2	265	0.4
Uniacke	20	0.6	405	0.7
West Olympia	30	0.8	330	1.4
West Sable	93	2.6	170	8.1
West Venture C-62	31	0.9	375	1.2
West Venture N-91	68	1.9	385	2.6
Total	1952.0	55.3		108.8

Table 2 Base Case Storage Capacity in Depleted and Stranded Fields (if produced).

fault of the field. Injecting 1 $MtCO_2$/year (similar to Sleipner or Snohvit, offshore Norway) into seven low-relief reservoirs, the organizer's simulation shows minor migration of CO_2 outside structural closure beginning early in the simulation (dependent on injection rate).

Economic models

The teams took fairly consistent approaches to screening economic models using published ranges of costs (e.g.: Leung et.al., 2014) and a Nova Scotia carbon price that increases by C$15/year to C$170/tonne in 2030 (e.g.: Gorman, 2022). UFBA modelled 7 $MtCO_2$/year of storage (similar to emissions from Nova Scotia power plants, Figure 7). The KUST team modelled 12 $MtCO_2$/year similar to 13.2 $MtCO_2$/year of emissions from Nova Scotia and New Brunswick power plants and refineries (CER – Canada Energy Regulator, 2017). If other measures were not in place, and it was required, 12 $MtCO_2$/year could dispose of about 75% of total Nova Scotia emissions in 2019 (16 $MtCO_2$: Government of Canada, 2021).

The KUST team presented a straightforward undiscounted model (Table 3), considering storage of 12 $MtCO_2$/year for 30 years which we present here as a basic template for discussion. We then use cost sensitivities from the UFBA team report and a range of potential carbon credits. Costs are commercially sensitive and can be difficult to estimate so we have compared the teams' costs to published benchmarks.

Carbon capture is the biggest hurdle. In Table 3 the cost of upgrading (mainly coal) power stations ranges from $7-13 billion which is ~$1-1.5 billion per plant if eight power stations and refineries are considered. Upgrades at the Boundary Dam project in Saskatchewan to achieve 1 $MtCO_2$/year cost US$1.5 billion in 2014 (MIT, 2016). Costs in a new project in Nova Scotia would probably be higher on a one-off basis but might be similar allowing for economies of scale and technological improvements.

Costs of transport, storage, and monitoring ($3-9 billion) can be broadly compared to the Sable Gas Project which 'reported spending C$2.8 billion ($2.2 billion) in Nova Scotia, (and) C$1.9 billion (US$1.5 billion), in royalties to the provincial government" (Jaremko, 2018).

The expenditures at Sable involved 22 wells, five production platforms, a compression platform and 340 km of pipelines (Jaremko, 2018) plus onshore gas and fractionation plants. A 12 $MtCO_2$/year storage project would probably involve about 17 wells based on a 0.7 $MtCO_2$/year/ well model in Ringrose and Meckel's 2019 analysis of the global effort to meet 2DS emissions reductions (two-degree scenario). These wells would likely be closer to land than the Sable wells unless synergies with stranded fields are considered (as suggested by a number of teams): for revenue, to drive compression, for enhanced recovery (IIT) possibly to prevent early water breakthrough in low relief fields. KUST suggested offshore wind power to generate compression and UiS suggested generation and storage of hydrogen in salt diapirs. In addition, engineering might be more cost effective than a Sable vintage project with increased use of subsea tie backs. With these considerations, the costs of transport and storage in Table 3, US$ 3-9 billion, might not be unreasonable at the higher end.

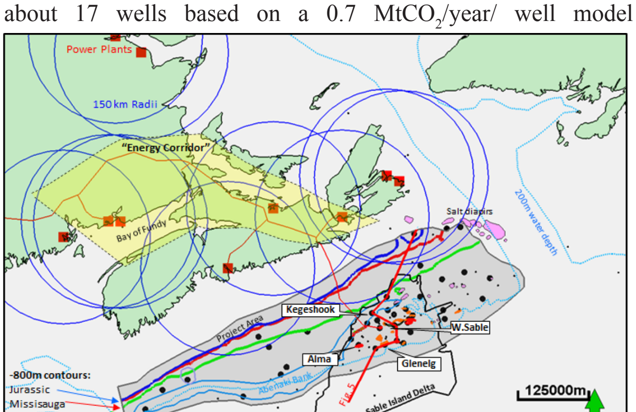

Figure 7 Power Plants with 150 km radii. Well log X section – TVDss. J150 (blue), K125 (red), K94 (green) at -800m Risk of leak up to base Dawson Canyon above -800m and free gas migrating to subcrop

Storage of 12 $MtCO_2$/year in Table 3 incurs base case costs of $US19.4 billion with a prize of $US21.6 billion over 30 years with carbon credits of US$60/tonne – an undiscounted profit of over $US2 billion. Applying a range of costs from the UFBA report and carbon credits up to $US150/tonne, undiscounted profits range up to US$54billion. If suitable incentives can be guaranteed, and costs can be managed, this could be a significant commercial opportunity for corporations with the capital and expertise to execute this type of project.

Strategic Plans

Given the considerable storage potential of the Scotian Shelf (probably multiple times annual global emissions of ~36 GtCO2 in 2021) and relatively low carbon emissions in the province, carbon neutrality in Nova Scotia is eminently feasible even if all provincial emissions were stored offshore. If costs, credits, and commercial drivers are compelling, the questions are how to select, optimize and phase storage locations; how to integrate this with onshore infrastructure in the so-called "Energy Corridor" (Dusseault and Wach, 2020); and how the upside potential of the offshore storage resource might be captured, considering carbon delivery and credits from northeastern North America and sea-borne delivery and credits from Europe. It is possible at this scale that a large commercial offshore industry could be developed that avoids the environmental and safety concerns that are common in inhabited areas onshore.

The teams focused offshore, with UiS presenting the most creative phased approach. Phase 1 would focus on CO2 injection into depleted fields (with 4D seismic monitoring similar to Sleipner Field, Norway as suggested by multiple teams) as well exploring the installation of a hydrogen storage facility. Phase 2

Scope	$MtCO_2$/year	12	12	12	Comments - comparison to benchmarks
	Years	30	30	30	
	Total $MtCO_2$	360	360	360	
Costs		KUST	UFBA: Low-High		
	Capture US$/t	35	20	25	At Boundary Lake upgrades to achieve 1 $MtCO_2$ / year cost US$ 1.5 billion in 2014. (MIT, 2016)
	Capture US$M	12,600	7,200	9,000	
	Transport US$/t	15.5	7.15	14.95	The Sable Gas Project (1998-2018) reportedly spent US$ 2.2 billion in Nova Scotia on a comparable, but larger project: 22 wells, 5 production and 1 compression platform, 340 km of pipeline (Jaremko, 2018) plus onshore gas and fractionation plants.
	Transport US$M	5,580	2,574	5,382	
	Storage US$/t	3.25	0.96	10.73	
	Storage US$M	1,170	346	3,863	
	Monitoring US$/t	0.2	0.1	0.3	
	Monitoring US$M	72.0	36.0	108.0	
	Total US$M	19,404	10,148	18,296	
Prize	Credits US$/t	60	60	60	The Carbon price in Nova Scotia is planned to reach C$170 by 2030.
	Total US$M	21,600	21,600	21,600	
Undiscounted Profit $M		2,196	11,452	3,304	$2-11 billion undiscounted profit
Prize	Credits US$/t	100	100	100	
	Total US$M	36,000	36,000	36,000	
Undiscounted Profit $M		16,596	25,852	17,704	$17-26 billion undiscounted profit
Prize	Credits US$/t	150	150	150	
	Total US$M	54,000	54,000	54,000	
Undiscounted Profit $M		34,596	43,852	35,704	$35-44 billion undiscounted profit

Table 3 Undiscounted economic model. KUST base case with UFBA cost sensitivities and carbon price sensitivities. Cost comparison to benchmarks.

would implement hydrogen storage in salt caverns, with further evaluation of deep saline aquifers in Phase 3, which would then be implemented in Phase 4 – probably in the Upper and Middle Missisauga Formations.

Several teams – including UiS, KUST & UFBA - identified the Missisauga Formation specifically as the most promising of the deep saline aquifers (ultimately resulting from its deposition when the Sable Island Delta was most prolific) but there is room for considerable research evaluating which of the major formations is most suitable. This would require balancing storage capacity and injectivity as functions of porosity, permeability, and net thickness with pipeline distance offshore (Fig.7) and depth of burial. The 800m subsea contour at the top of each of the major stratigraphic intervals is shown in Fig.7. With the exception of the Abenaki Carbonate Bank, reservoirs / aquifers become shallower, less compacted, more proximal, and better quality, landward. However, intraformational and sub-regional seals are less well-developed in this direction introducing containment concerns. Evaluating the relative merits of the key formations should involve dynamic modeling with much finer grids and more detailed stratigraphic architecture, considering different styles of channel systems and intervening non-reservoirs that enhance dispersal, residual trapping and dissolution of CO2: massive inter-cutting fluvio-deltaic distributaries in the Missisauga Formation; cyclical shallow marine parasequences with abundant, relatively thin, sand-filled estuarine channels in the Logan Canyon Formation – both evident on 3D seismic data (e.g.: Kendell and Deptuck, 2012; OERA, 2011).

A further consideration is pore pressure in deep saline aquifers. Inboard of successive forestepping shelf-margins the monoclinal delta is dominantly normally pressured at prospective storage depths (as is the Abenaki Carbonate Bank) but at the deltaic shelf-margins, overpressures in confined growth-fault controlled depocentres ("expansion trends": Pe-Piper and Piper,

2012) increase incrementally with depth up to fracture closure pressures (Wielens 2003). This is the result of a dynamic pressure system with pressure entry via disequilibrium compaction and hydrocarbon generation and ongoing pressure release via limited cross-fault juxtapositions between pressure compartments (Richards et al., 2008; Skinner, 2016). In principle, overpressure infers containment, but the complications associated with drilling into overpressure (particularly with varying levels of pressure depletion in fields such as Thebaud and Venture) probably favors hydro-pressured aquifers and fields – not to mention additional drill-depth, and well integrity issues in depleted, originally overpressured, fields.

A fundamental issue is whether to favor deep saline aquifers with their enormous storage potential or depleted / stranded fields that have conventional oil and gas traps. If a test site for deep saline aquifers were to be considered, the Upper and Middle Missisauga Formations in the vicinity of the Kegeshook well (Figures 5 and 7) would meet the criteria of aquifer quality, depth, and well-developed topseals (Naskapi Shale and "O" Marker).

Among the depleted and stranded fields, Alma and Glenelg received particular attention from the teams. Alma at around ~2800m subsea is the largest, shallowest, and simplest of the depleted gas fields. Of the stranded fields, Glenelg is one of the shallowest (~3200m subsea). Both have hydro-pressured Upper Missisauga aquifers, below thick Naskapi Shale at the shelf-margin of the delta – which puts them ~200km offshore. Glenelg does have some compartmentalization with multiple contacts in three major fault blocks that result from "Mercedes-Benz" faulting above a footwall salt diapir (similar to Onondaga and Thebaud). This might stimulate speculation that monetization of a stranded field (P50 508 BCF) could be combined with carbon storage in a depleted field and possible hydrogen / carbon storage in a salt diapir. Along these lines, the shallow (~1400m subsea) West Sable Field (P50 resource 93 BCF gas, 18 MBO oil and condensate), which was discovered by one of the early wells in the basin in 1971, sits above a salt diapir penetrated by a subsequent well at ~3000m subsea.

Conclusion

This competition presented student teams on five continents with a blizzard of data and published information and some ambitious technical goals that have never been addressed previously on the Scotian Margin - a "real-world" project with added complexity during in the Covid epidemic, when team interaction is at a premium in a multi-disciplinary project. The results are very encouraging presenting local, regional, and intercontinental scale opportunities.

The teams each attacked the project in their own way and are to be congratulated: providing confidence where solutions converged and, possibly more importantly, stimulating new ideas and discussion where they did not. It reinforces the notion that as we progress the energy transition there is a spectacular base-level of offshore geoscience and engineering knowledge that can be applied to any enterprise involving fluid flow in porous media: oil and gas production, carbon storage, hydrogen or methane storage, aquifer management, open-loop geothermal energy, and technologies that have not even been thought of yet.

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The 'Minus CO2 Challenge 2021' top 4 teams:

First Place – Indian Institute of Technology Bombay (India)

- Ahmed Samir Muhammad Rizk
- Amaar Imdad Siyal
- Ahmed Khaled Alzaabi
- Marwa Mohammed Alblooshi
- Omar Abdulrahman Al Attas

Second Place – Federal University of Bahia (Brazil)

- Matheus Radamés Silva Barbosa
- Mariana Rosário Conceição Sampaio
- Marcos Reinan de Assis Conceição
- Alexsandro Guerra Cerqueira

Third Place – Khalifa University (United Arab Emirates)

- Arpita Chakraborty
- Firdush Zallah Hussain
- Rhythm Shah
- Sonal Janagal
- Sushmita Rangnath Mastud

Fourth Place – University of Stavanger (Norway)

- Kyle Watts
- John Paul Masapanta Pozo
- Aigul Akberova
- Martín Eduardo Coffey
- Orlando Butar Butar

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